BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 88-11-E - ORDER NO. 88-864

AUGUST 29, 1988

IN RE: Application of Carolina Power & Light Company for General Increase in Rates and Charges.	)))	ORDER GRANTING INCREASE

On March 1, 1988, Carolina Power & Light Company (Applicant, Company, or CP&L) filed an Application with the Public Service Commission of South Carolina (the Commission) seeking authority to adjust and increase electric rates and charges for retail customers served by the Company in South Carolina. The Application sought rates that would produce approximately $47.8 million of additional annual revenues from the Company's South Carolina retail operations when applied to a test period consisting of the 12 months ended September 30, 1987, for an approximate 14.90 percent increase in total South Carolina retail rates and charges. The Company requested that increased rates be allowed to take effect after approval by the Commission but no later than September 1, 1988.

The principal reasons set forth in the Application necessitating the requested increase in rates were: (1) the need to include in rates the Harris Plant investment deferred pursuant to the Commission's Order in Docket No. 87-7-E, Order No. 87-902; and (2) the need to recover the costs associated with adding new transmission and distribution facilities, maintenance and

modification work at generation facilities, and other increases in the Company's overall cost of providing service.

Petitions to Intervene were received from the South Carolina Department of Consumer Affairs (the Consumer Advocate); the South Carolina Energy Users Committee (SCEUC); Shaw Air Force Base, South Carolina, on behalf of the Federal Executive Agencies of the United States (Shaw); and Nucor Steel, a Division of Nucor Corporation (Nucor).

By memorandum dated February 19, 1988, the Commission notified the Company to prefile with the Commission and serve upon all parties of record on or before March 15, 1988, the testimony and exhibits of the witnesses it intended to present. On March 15, 1988, the following testimony was filed:

1. A Panel consisting of Sherwood H. Smith, Jr., President, Chief Executive Officer and Chairman of the Board of Directors of CP&L; M.A. McDuffie, Senior Vice President - Nuclear Generation for CP&L; and Roland M. Parsons, Project General Manager - Completion Assurance for CP&L's Harris Project;

2. Dr. James H. Vander Weide, President of Financial Strategy Associates and Research Professor of Finance and Economics at Fuqua School of Business, Duke University;

3. Thomas S. LaGuardia, President TLG Engineering, Bridgewater, Connecticut;

4. Paul S. Bradshaw, Vice President and Controller of CP&L;

5. David R. Nevil, Manager--Rate Development and Administration in the Rates and Service Practices Department of CP&L; and

6. Norris L. Edge, Vice President--Rates and Service Practices Department of CP&L.

On May 17, 1988, the Commission issued a memorandum notifying the parties that a prehearing conference of the parties of record would be held in the offices of the Commission on June 10, 1988 at 11:00 a.m. On May 31, 1988, the Commission issued a memorandum requiring that the Commission Staff and all other parties of record except the Company prefile with the Commission and serve on all parties on or before June 13, 1988 the testimony and exhibits of the witnesses intended to be presented. On June 3, 1988, Nucor requested an extension of time until June 15, 1988 to file prefiled testimony which was granted by the Commission on June 6, 1988. The prehearing conference was held as scheduled on June 10, 1988.

On or about June 15, 1988, the following testimony was filed: for the Consumer Advocate - Philip E. Miller, Utility Regulatory Consultant; Dr. Michael J. Ileo, Technical Associates, Inc.; and John B. Legler, Professor of Banking and Finance, University of Georgia. For the South Carolina Public Service Commission Staff - A. R. Watts, William C. Sheely, Jr., Dr. R. Glenn Rhyne, and Curtis Price. For Nucor - F. Kenneth Iverson, Chairman of the Board and Chief Executive Officer, Nucor

Corporation; Charles Komanoff, Komanoff Energy Associates; a panel consisting of John T. Stiefel, Stiefel Associates, Inc. and James P. McGaughy, Jr., GDS Associates, Inc.; and Dr. Dennis W. Goins, Potomac Management Group. For the South Carolina Energy Users Committee - Nicholas Phillips, Jr., Drazen-Brubaker & Associates, Inc., and Kenneth W. Stueber, DuPont Company. For Shaw Air Force Base - Richard I. Chais, ORI, Inc.

In a procedural Order dated June 17, 1988, the Honorable Franklin E. Robson, Esquire, Administrative Law Judge, ruled that the appearance of panels of witnesses would not be allowed because of due process considerations. Accordingly, on June 22, 1988, the Company filed a letter designating the division of responsibilities among its individual witnesses originally filing testimony as a panel.

Thereafter, pursuant to notice duly provided in accordance with applicable provisions of law and with the Commission's Rules and Regulations, a public hearing relative to the matters asserted in the Company's Application was commenced in the offices of the Commission on June 27, 1988, the Honorable Franklin E. Robson, Esquire, Administrative Law Judge, presiding.[1]

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[1]The Administrative Law Judge presided over the procedural aspects of the proceeding, pursuant to S. C. Code Ann. Section 58-3-60 (1976), as amended.

William F. Austin, Esquire, Robert W. Kaylor, Esquire, Richard E. Jones, Esquire, and Edward M. Roach, Jr., Esquire, represented the Company; Steven W. Hamm, Esquire, Raymon E. Lark, Jr., Esquire, and F. David Butler, Esquire, represented the Intervenor, the Consumer Advocate; Arthur G. Fusco, Esquire, appeared on behalf of SCEUC; Francis P. Mood, Esquire, and Garrett A. Stone, Esquire, appeared on behalf of Nucor, Intervenor; G. Edward Welmaker, Esquire; and Major Gary A. Enders, appeared on behalf of Shaw; and Sarena D. Burch, Esquire, Staff Counsel, represented the Commission Staff.

On July 8, 1988 and July 11, 1988, the Company filed rebuttal testimony of M.A. McDuffie and Roland M. Parsons of CP&L and Dr. Robert Spann of ICF, Inc.

The public hearing before the Commission was completed on July 13, 1988. The Administrative Law Judge granted leave to all parties to file briefs or proposed orders with the Commission. Briefs or proposed Orders were to be filed by August 5, 1988. A night hearing was held in Darlington, South Carolina on July 21, 1988.

Based upon the verified Application, the tesimony, and exhibits received into evidence at the hearings and the entire record of these proceedings, the Commission now makes the following findings of fact:

FINDINGS OF FACT

1. CP&L is engaged in the business of developing, generating, transmitting, distributing, and selling electric power and energy to the general public within the northeastern area of South Carolina and a broad area of eastern and western North Carolina.

2. CP&L is an electric utility organized and operating in the States of South Carolina and North Carolina where it is engaged in the generation, transmission, distribution, and sale of electricity to the public for compensation. The Company's retail operations in South Carolina are subject to the jurisdiction of this Commission pursuant to S. C. Code Ann. Sections 58-27-10 et seq. (1976). The Company's retail operations in North Carolina are subject to the jurisdiction of the North Carolina Utilities Commission (hereinafter "NCUC"); the Company's wholesale operations in South Carolina and North Carolina are subject to the jurisdiction of the Federal Energy Regulatory Commission (hereinafter "FERC").

3. The test period for purposes of this proceeding is the 12-month period ended September 30, 1987, adjusted for certain known and measurable changes.

4. CP&L, by its Application, is seeking an increase in its basic rates and charges to its South Carolina retail customers of $47.8 million.

5. The one-hour summer coincident peak (1CP) demand allocation methodology is the most appropriate method for making jurisdictional allocation of production costs and for making fully distributed cost allocations among customer classes in this proceeding. Consequently, each Finding of Fact appearing in this Order which deals with the overall level of rate base, revenues, and expenses for South Carolina retail service has been determined based upon the 1CP allocation method.

6. The appropriate operational revenues for CP&L for the test year under present rates and after accounting and pro forma adjustments are $322,664,000 for service to the South Carolina retail jurisdiction.

7. Although the Commission is not pursuaded that the costs of the Harris Plant were imprudently incurred, an equitable sharing of the risks of some common facilities' costs through amortization without a return being earned on the unamortized balance is appropriate.

8. The reasonable level of test year operating revenue deductions for the Company after pro forma adjustments and the Harris Deferral is $254,700,000.

9. The reasonable rate of return on common equity that CP&L should be allowed an opportunity to earn is 12.75 percent, and this is the percentage that the Commission adopts for this proceeding. Combined with the debt and preferred cost rates and the normalized capital structure set forth in the table below,

which the Commission finds reasonable, the overall rate of return is 10.48 percent.

Item	Percent	Weighted Rate	Cost
Long-Term Dept	47.82%	8.62%	4.12%
Preferred Stock	7.46%	8.75%	0.65%
Common Equity	44.72%	12.75%	5.71%
TOTAL	100.00%	-	10.48%

10. The reasonable allowance for total working capital and materials and supplies in rate base is $30,159,000.

11. CP&L's reasonable original cost rate base used and useful in providing service to the public within the State of South Carolina is $804,023,000, consisting of electric plant in service of $1,053,723,000; net nuclear fuel of $28,758,000; plant held for future use of $2,562,000; materials and supplies of $16,990,000; and allowance for working capital of $13,169,000, reduced by accumulated depreciation and amortization of $204,888,000, accumulated deferred income taxes of $105,376,000, and customer deposits of $915,000.

12. Based upon the foregoing, CP&L should increase its annual level of gross revenues under present rates by $24,980,000. The annual revenue requirement approved herein is $347,644,000 which will allow CP&L a reasonable opportunity to earn the rate of return on its rate base which the Commission has found just and reasonable.

Class of Service	Approved Increase
Residential Service Class	$ 9,154,903
Small General Service Class	9,952,405
Large General Service Class	5,828,196
Lighting Service Class	44,496
TOTAL RATES	$24,980,000
Other Electric Operations	-0-
TOTAL JURISDICTIONAL (Retail Electric)	$24,980,000

13. The rate designs, tariffs, riders, and service regulations approved by the Commission and the modifications thereto as described herein are appropriate and should be adopted.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1 AND 2

The evidence supporting these findings concerning the Company's business and legal status is contained in the Company's verified Application and in prior Commission Orders in this Docket of which the Commission takes notice. These Findings of Fact are essentially informational, procedural, and jurisdictional in nature; and the matters which they involve are essentially uncontested.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3 AND 4

The evidence for these findings concerning the test period and the amount of the revenue increase requested by the Company is contained in the verified Application of the Company and the testimony and exhibits of CP&L witnesses Smith, Vander Weide, Bradshaw, LaGuardia, Nevil, and Edge.

On March 1, 1988, the Company filed an Application requesting approval of rate schedules designed to produce an increase in gross revenues of $47.8 million. The Company's filing was based on a test period consisting of the 12 months ending September 30, 1987. The test period, not being challenged by any party, is therefore approved.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 5

The evidence for this finding concerning the proper production allocation method consists primarily of the testimony and exhibits of Company witness Nevil, Commission Staff witness Sheely, SCEUC witness Phillips, Consumer Advocate witness Ileo, and Nucor witness Goins.

CP&L provides service in two states as well as wholesale service to certain municipalities and electric membership cooperatives and supplemental service to North Carolina Eastern Municipal Power Agency (NCEMPA). For this reason, it is necessary to allocate the cost of service among jurisdictions and among customer classes within each jurisdiction. In this proceeding, the Company based its application on the use of the one-hour coincident peak (1CP) method, as directed by the Commission in its order in the Company's last rate case, Docket NO. 87-7-E.

Commission Staff witness Sheely and Nucor witness Goins supported the continued use of the 1CP method. SCEUC witness Phillips testified that the 1CP method was appropriate for CP&L.

He stated that the Commission has consistently ordered the use of the 1CP method for CP&L in South Carolina. In addition he recommends the use of the minimum system technique for determining the customer-related cost component of its distribution system.

Consumer Advocate witness Ileo recommended that a 12CP methodology be adopted for allocating production plant. Dr. Ileo testified that the 1CP method will produce unstable results from one test year to another and that the contributions each class makes to the peak demand may vary considerably depending upon when the system peak occurs. He also suggested that the Commission direct the Company to perform a cost-of-service study in the next filing in which demand and energy costs are differentiated by season and time of day. (TR. Vol. 15 at 10-25).

The Commission continues to believe that a 1CP demand allocation methodology is most appropriate for CP&L and therefore adopts that methodology for allocation of production level demand-related costs. The Commission also concludes that CP&L's cost-of-service studies have provided ample support for the determination of all issues in this case and it is therefore unnecessary for CP&L to provide alternative studies, as requested by the Consumer Advocate, at additional cost to the ratepayer. The Commission also denies the request of SCEUC witness Phillips concerning use of the minimum system technique.

Another allocation issue relates to the appropriate demand to include in the 1CP allocation factor as a result of industrial customer Nucor taking service under Rider No. 58. Nucor witness Goins suggested that because Nucor had begun to take service under Rider No. 58, the Curtailable Service Rider, a pro forma adjustment should be made to the test year 1CP value to reflect a lower demand for the South Carolina retail jurisdiction. Nucor's position is that CP&L made a revenue adjustment to reflect the reduction in revenues CP&L would receive from Nucor due to its electing to take serivce under Rider No. 58, and CP&L should also make a corresponding adjustment to the allocation factor. As an alternative should the Commission not allow the allocation factor adjustment, the Revenues adjustment of $2,222,734 should be disallowed.

CP&L witness Nevil testified that CP&L was already experiencing a reduction in its revenue due to Nucor's electing service under Rider No. 58 and that until rates were changed to reflect this fact, the CP&L shareholders would suffer this loss. He testified that this revenue reduction was a known and measurable change. He further testified that the demand Nucor would place on the CP&L system was not certain in the future, and he referred to the testimony of Nucor CEO Iverson which indicated that Nucor's election to take service on Rider No. 58 was on a trial basis. Mr. Nevil further testified that if you "opened the door" on allocation factor adjustments, there were other

potential adjustments such as annualizing water heater and air conditioner load control effects or recognition of standby requirements, which would have to be made in addition to the one recommended by Nucor. Mr. Nevil testified that including these allocation factor adjustments would result in an increase of $2.8 million in the South Carolina retail revenue requirement. (TR. Vol. 4 at 42-43) Staff witness Sheely testified that Nucor was not on Rider No. 58 at the time of the system peak and that an adjustment to the allocation factor as proposed by Nucor would be an adjustment to per book allocation factors and that past Commission practice has been not to adjust per book allocation factors.

The Commission finds that the proposed revenue adjustment of $2,222,734 is not sufficiently known and measurable to be accepted for the purposes of this proceeding and therefore disallows same. In light of this finding, Nucor's proposed allocation adjustment is not appropriate.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 6

The evidence for this finding concerning the adjusted level of operating revenues is found in the testimony and exhibits of Company witness Nevil, Commission Staff witness Watts, and Nucor witness Goins.

CP&L witness Nevil's exhibits reflected adjusted operating revenues under current rates of $320,180,370. Commission Staff witness Watts testified that the Staff disagreed with the

Company's allocation of a portion of the Cogeneration Revenue Annualization adjustment, which was a component of Mr. Nevil's recommended adjusted revenues. The Company directly assigned the three components of the cogeneration revenue adjustment (transmission, distribution, and customer) to the jurisdiction from which those revenues were provided. Staff witness Watts recommended that the transmission portion of the adjustment be allocated by the Demand Power Supply allocator which would allocate $20,000 more revenue to the South Carolina retail jurisdiction. (TR. Vol. 19 at 219). He also recommended an adjustment of $241,000 to reflect additional revenues from a standby service customer. The Company did not contest either of Mr. Watts' recommendations, and the Commission adopts these recommendations as appropriate in this case.

A second issue related to the appropriate level of adjusted operating revenue in this case was addressed by Nucor witness Goins. Dr. Goins proposed an additional $4.1 million revenue reduction to reflect his proposed demand allocation adjustment. Witness Goins concurred that if no demand allocation adjustment was approved disallowance of the Company's $2,222,734 adjustment would be appropriate. As discussed in Finding of Fact No. 5, the 1CP methodology with no adjustment to demand allocation was approved, and the Commission has disallowed the $2,222,734 revenue adjustment for reasons set forth supra.

Based on these conclusions, the appropriate level of operating revenues for the Company under present rates after accounting and pro forma adjustment is $322,664,000.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 7

The evidence for this finding concerning CP&L's expenditures on the Harris Plant is contained in the testimony and exhibits of Company witness Smith, Parsons, McDuffie, and Spann; Nucor witnesses Stiefel, McGaughy, and Komanoff; and Commission Staff witness Watts.

CP&L is seeking here to include its investment in the Harris Plant in its rate base. The Commission in its 1987 Order No. 87-902 in Docket No. 87-7-E included 50 percent of the Company's investment in the plant in rate base under bond and withheld its final decision as to including any portion of the plant until the instant proceeding. The Commission has heard challenges by witnesses sponsored by intervenor Nucor to the prudence of the Company's expenditures on the plant.

The Harris Plant was announced by CP&L in 1971 as a four-unit, 3,600 MW nuclear plant located near Raleigh, North Carolina. The four units were originally scheduled for completion in 1977, 1978, 1979, and 1980. Harris Unit Nos. 3 and 4 were cancelled in 1981, and Unit No. 2 was cancelled in 1983. This Commission has dealt with the investment in those units previously, and that is not an issue here.

Harris Unit No. 1 entered commercial operation on May 2, 1987, at a cost of approximately $3.9 billion. The Harris Plant cost significantly more and took longer to build than was originally anticipated. The Company has the burden of proving the reasonableness of the expenditures on the plant; and as noted above, challenges have been made to the reasonableness of those expenditures.

When the reasonableness of utility expenditures is challenged, the appropriate standard for determining the controversy is the traditional prudence standard. Under that standard, the Commission determines whether utility management decisions were made in a reasonable manner and at an appropriate time based on what was reasonably known or reasonably should have been known at that time. See, e.g., Consolidated Edison Company of New York, 45 P.U.R. 4th 325 (N.Y.P.S.C. 1982). The Commission notes that the determination of reasonableness should be based on a contemporaneous view of the action or decision under question.

In its initial filing in its direct case on March 15, 1987, the Company presented testimony by its Chairman and Chief Executive, Mr. Sherwood Smith; its Vice President of Nuclear Operations, Mr. M.A. McDuffie; and Mr. Roland Parsons, the Project General Manager on the issue of the Harris Plant expenditures. Mr. Smith's testimony presented an account of the corporate decision-making concerning the plant and the external and Company internal events that had impacted the plant. To

summarize, the four-unit Harris Plant was started in 1971 at a time when CP&L was experiencing one of the highest growth rates of any utility in America. Harris was part of a massive construction effort undertaken by the Company to meet the projected growth in demand. Very high annual growth in peak demand continued through 1973 when the OPEC oil embargo occurred. The effects of this embargo were several fold, but the major impacts were on the Company's financial condition and on customer demand. According to CP&L's witnesses to counter these effects, CP&L deferred a number of its plants, including the Harris Plant, and indefinitely postponed others.

In 1975, the Company again moved to defer the Harris units and other units. The in-service date of Harris Unit No. 1 was deferred from 1981 to 1984, and the other units were similarly deferred. These actions were taken in an attempt to improve the Company's financial conditions and to put it in a better position to finance the heavy construction costs anticipated in the future. The plant deferrals were possible because of a combination of declining demand growth projections and a reduction in the Company's planning reserve margin to 12 percent.

CP&L began construction of the Harris Plant in January 1978, after receipt of the Construction Permits from the Nuclear Regulatory Commission (NRC). Company witnesses testified that the cost of constructing that plant increased for a number of reasons, including record-high inflation and interest rates and

an increase in the regulation of nuclear plants by the NRC. At the same time, CP&L's projections of demand growth continued to decline and eventually stabilized at a level much lower than was projected at the time the plant was initiated. Due to decreased projection of demand growth, higher costs, and uncertainty over future NRC regulations, CP&L cancelled Harris Unit Nos. 3 and 4 in 1981 and Unit No. 2 in 1983. Certain facilities had to be completed to serve Unit 1 which are large enough to serve the four units orignially contemplated. See, infra, for treatment of the costs associated with these facilities. This also increased the cost per kilowatt of Unit 1 compared to many other nuclear plants.

The Harris Plant was not the only plant CP&L had under construction during the 1970's and 1980's. During this time, CP&L completed approximately two-thirds of the generating system it now has available to meet the demands of its customers. Since 1971, the Company has had to make a number of decisions and commitments in order to meet the expanding needs of its service area; and since the Harris Plant was started, the Company has completed four nuclear units, five coal units, and twenty-two combustion turbines. Decisions concerning the Harris Plant had to be made in the context of this large overall construction program.

CP&L witnesses McDuffie, who was the Company officer responsible for the Harris Plant, and Parsons, who was the

Project General Manager, presented testimony concerning how the Company organized the Harris Project, chose the major contractors and the plant design, and implemented the project concept. Based on the experience gathered from a construction program that was continuous from 1947 to 1971 and that contained both fossil and nuclear plants, CP&L decided to assume the roles of Construction Manager and Project Manager on the Harris Project. It hired Ebasco Services, Inc., (Ebasco) as the architect/engineer (A/E) and Daniel Construction Company as the constructor. Westinghouse Electric Corporation was awarded the Nuclear Steam Supply System (NSSS) and turbine contracts. These CP&L witnesses described how the Company managed all aspects of the project, ranging from engineering management to quality assurance to project controls.

Witness Parsons provided testimony concerning the increases in the cost and schedule of the Harris Plant. Mr. Parsons presented the results of a study as to why the plant cost has increased between the definitive project estimate (done in 1978) of approximately $1.4 billion and the final plant cost of approximately $3.9 billion. The study analyzed the causes, or cost drivers, that had been identified as affecting plant cost. Of these cost drivers, the most significant, according to the study, was regulation, which accounted for 66 percent of the increase in cost. Mr. Parsons also addressed how and why the construction schedule for the Harris Plant had increased from 73 months (Construction Permit to Commercial Operation) to 111

months. Witness Parsons identified a number of regulatory changes that accounted for a significant portion of this 38-month schedule increase. (TR. Vol. 12 at 65-66)

CP&L witnesses Parsons and Smith presented testimony concerning how regulation of nuclear plants had changed throughout the duration of the Harris Project. The Company witnesses gave a number of specific examples of how new or interpreted regulations had been applied to the Harris Plant and how these had affected the plant. (TR. Vol. 12 at 61-65; TR. Vol. 7 at 32-33)

The CP&L witnesses also testified that, in addition to an increase in the number of regulations, the NRC's manner of regulation changed following the Three Mile Island (TMI) accident in 1979 and also as a result of quality assurance problems identified at other plants shortly after TMI.

Nucor presented the testimony of three witnesses who challenged the prudence of CP&L's expenditures on the Harris Plant. John T. Stiefel of Stiefel Associates, Inc., a company participating in nuclear consulting work and real estate, and James P. McGaughy, Jr., of GDS Associates, Inc., an engineering consulting firm, testified that CP&L failed to exercise prudent management judgment in the selection of the original design of the plant general arrangement and in its decision to manage the Harris Plant project itself. These witnesses also testified that CP&L had not prudently managed the impact of regulation on the

plant and had not adequately explained the reasons for cost increases. These witnesses developed a range of alleged imprudent costs of $569 million to $1.562 billion and recommended a disallowance of $880 million on a system basis.

Nucor also presented the testimony of Charles Komanoff of Komanoff Energy Associates, an energy and economic consulting firm. Mr. Komanoff presented a comparative analysis, based on regression analyses, of the cost of the Harris Plant to other nuclear plants. He also conducted an economic evaluation of the total life-cycle cost of Harris as compared with a hypothetical coal plant. Based on these comparisons, Mr. Komanoff found an "implied disallowance range" of $956 million to $1.236 billion.

Staff witness Watts recommended a portion of the Harris Unit No. 1 be considered as abandoned plant as it was originally designed and constructed as a functional part of units three and four which were previously abandoned. This amounted to $140,649,535 on a system basis and $20,038,179 to South Carolina retail jurisdiction. Staff also proposed a corresponding ten year amortization of these expenses with no earnings as has been approved by the Commission on other abandonments. Witness Watts testified that another alternative could be to spread these costs over the remaining license life of the plant which is approximately thirty-eight (38) years.

Under cross-examination by Staff counsel Burch, Company witness Parsons more specifically quantified the additional

expense above the stand alone cost of Harris Unit No. 1 as $440,000,000 with the total Spent Fuel Storage building included as an integral part of the Unit No. 1 facility. The Spent Fuel Storage facility costs amounted to $130,000,000.

Consumer Advocate witness Miller proposed a reduction to the allowed Harris plant cost due to his determination that certain of the expenses represented excess capacity that is not used and useful. This was quantified as approximately $141,000,000 based on a design consisting of two pairs of units rather than the four unit cluster. During cross-examination, Miller indicated it would be consistent with his position to also eliminate those costs of the common facilities associated with the companion unit to Unit No. 1. This modification resulted in a change in his proposed excess common facilities to $569,000,000. In its Brief, the Consumer Advocate further proposed to disallow an additional $241,000,000 due to the Company's inability to reasonably quantify the cost effects of errors and omissions on the project by its own personnel, and its contractors and vendors.

The Commission has thoroughly examined the evidence in the record contributing to the ultimate Harris plant costs and concludes that, although the Commission is not pursuaded that the expenditures associated with the Harris Plant were imprudently incurred, it should exclude the costs from rate base incurred above that necessary for Harris Unit No. 1 to exist as a stand alone unit but does not remove any of the cost of the Spent Fuel

Storage Facility as the Commission is convinced that this facility is an asset to CP&L and its ratepayers. The Company will be allowed to recover these expenses in equal annual amounts over the remaining license life of the Harris nuclear plant, but will not be allowed to earn any return that may otherwise have accrued due to these dollars. The Commission finds this disallowance and subsequent amortization without a return over the license life of the facility to be an appropriate and equitable sharing of the risks, benefits, and costs among the Company, the shareholders, and ratepayers.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 8

The evidence for this finding concerning the reasonable level of test-year operating revenue deductions is found in the testimony and exhibits of Company witnesses Bradshaw and LaGuardia; Commission staff witnesses Price, Sheely, and Watts; and Consumer Advocate witness Miller.

Unless otherwise specified, all numbers throughout the remainder of the Order are allocated as South Carolina retail. The differences between the Company and the Commission Staff concerning the proper level of operating revenue deductions included in test-year operations are reflected in the following table:

Operating Revenue Deductions	Company ($000s)	Commission Staff ($000s)	Differences ($000s)
Operating & Maintenance Expenses	177,566	177,926	360
Depreciation Expense	40,050	36,901	(3,149)
Taxes Other Than Income	11,224	11,220	(4)
Current Income Taxes	9,360	11,164	1,804
Deferred Income Taxes	10,152	9,967	(185)
Deferred Investment Tax Credits	1,959	1,991	32
Interest on Customer Deposits	110	110	0
Harris Deferral	6,156	5,982	(174)
Total Operating Revenue Deductions	256,577	255,261	(1,316)

The first area of disagreement concerns operations and maintenance (O&M) expenses. The differences related to O&M are set forth in the following table:

Item	Difference ($000s)
Officers' Salaries	(8)
Harris Plant O&M	(1,128)
Misc. General Expense	(10)
Amort. of Harris 1 Abandonment	2,004
Pension Expenses	(178)
Co-Gen Capacity	(54)
Co-Gen Non-Fuel Energy	(267)
Harris Levelization	1
Other O&M	-
Total O&M Expense	360

The first area of difference among the Company, the Commission Staff, and the Consumer Advocate relates to the Company's officers' salaries. Commission Staff witness Price recommended that the Company's O&M expenses be reduced by $8,037 which represents the difference in the level of officers'

salaries between the 12 months ended September 1987 and the 12 months ended September 1986. Consumer Advocate witness Miller also recommended that an adjustment be made to reduce O&M by $43,000 which represents the test-year increase in officers' salaries. Witness Miller testified that this Commission made a similar adjustment in the Company's last general rate case. (TR. Vol. 14 at 186).

The $43,000 officers' salary elimination used by witness Miller came from CP&L's response to Staff Data Request No. 1, Question 64(G). This question asks for increases granted to officers during the test year who were officers at the beginning of the test year through the end of the test year. The Staff used an elimination adjustment of $8,037 which consisted of setting the officers' salaries at the 1986 level after considering promotions and terminations. The Commission finds Staff's adjustment which has as its source, Staff Data Request No. 1, Response 64(a), more appropriate in that Staff's adjustment allows for the net change in total officers' salaries.

The next disagreement between the Company and the Commission Staff relates to the appropriate level of Harris O&M expenses to include in this proceeding. The Company made an adjustment to increase test-year O&M expenses by $6,120,515 to reflect an annualized level of operating expenses of $9,183,635 for the Harris Plant. The basis for the Company's adjustment was the 1987 Harris Plant budget estimate.

Witness Sheely testified that the Staff recognized the need for an adjustment to reflect the added expense of operating the Harris Plant over the per books amount included in the test year. Witness Sheely proposed that O&M expenses for the Harris Plant be annualized based on actual dollars expended for the period May 1987 through March 1988. His adjustment resulted in a reduction of $1,127,473 to the Company's proposed expense level.

Consumer Advocate witness Miller recommended that the Harris Plant O&M expenses included in this case be reduced by $868,542. His recommendation was based on the annualized May through December 1987 actual O&M expenses for the Harris Plant. (TR. Vol. 14 at 180)

The Commission, after considering all the evidence in this proceeding, finds that the expense level recommended by the Staff should be adopted for purposes of this proceeding because the Staff based its adjustment on actual dollars expended for a longer period.

The next difference among the Company, the Commission Staff, and the Consumer Advocate relates to miscellaneous general expenses. The Commission Staff and the Consumer Advocate made an adjustment to eliminate $9,739 from O&M expenses for the Company's sponsorship of sports teams, Pioneer Club expenses, and employee club dues. Consumer Advocate witness Miller testifed that these expenses should be eliminated because they do not provide a direct and primary benefit to the ratepayers. He

further stated that his adjustment was consistent with the Commission's order in the Company's last general rate case. (TR. Vol. 14 at 206)

After considering all the evidence on this matter, the Commission adopts the adjustments proposed by the Staff and Consumer Advocate as have been adopted in prior rate cases.

The next area of disagreement between the Company and the Commission Staff is related to the Commission Staff's adjustment to amortize over ten years that portion of Harris Unit No. 1 that the Staff considers abandoned plant and an alternative adjustment of amortization over the remaining life of the plant, or 38 2/3 years. As discussed in Finding of Fact No. 7, the Commission has removed from the rate base a portion of the Harris Plant. The Commission finds that Staff's alternate proposal to amortize over the remaining license life of 38 2/3 years without a return is the most appropriate and should be approved.

The next area of disagreement among the Company, the Commission Staff, and the Consumer Advocate is the proper level of pension expenses to include in O&M.

Commission Staff witness Price recommended reducing O&M expenses by $177,455 for pension expenses. This adjustment reflects the provisions of the Financial Accounting Standards Board Statement No. 87 (FASB No. 87) which were effective January 1, 1987. Consumer Advocate witness Miller made a similar adjustment. He testified that the test year pension expense

should be adjusted to reflect the 1987 expense level. (TR. Vol. 14 at 187)

On cross-examination, Company witness Bradshaw stated that while the pension expense can fluctuate from year to year, the 1987 level was representative of the pension expense level the Company is currently experiencing.

Based on the evidence presented, the Commission finds that test year O&M expenses should be reduced by $177,455 to reflect the 1987 level of pension expense pursuant to FASB No. 87.

The Company, the Commission Staff, and the Consumer Advocate also disagreed on the proper level of cogeneration expenses to include in test year expenses. The Company included in O&M expenses increased costs of cogeneration capacity and non-fuel energy to reflect the addition of three new cogeneration units. The Company's adjustment was based on 1989 contract rates. This adjustment increased O&M expenses by $2,197,740. Company witness Nevil testified on cross-examination that 1989 cogeneration rates were used because the Company did not anticipate filing a general rate case for some time. The 1989 level would therefore be more reflective of costs when the rates in this case are effective.

Commission Staff witness Sheely made an adjustment to increase O&M expenses by $1,876,400. Witness Sheely based his adjustment on the 1988 contract rates which would be the rates in effect at the time revenues set in this proceeding become effective.

Consumer Advocate witness Miller omits this adjustment in total and states that this adjustment is a post test year adjustment which incorporates costs that are beyond both the hearing date and the order date in this proceeding. (TR. Vol. 14 at 188-89)

The Commission believes that we should encourage the development of cogeneration and to deny contract rates is an inappropriate signal to this Company. We therefore agree with the Company and the Staff that the adjustment should be made and that the 1988 contract rates as proposed by Staff should be approved.

The next O&M issue between the Company and the Staff concerns the proper amount to include in O&M expenses for the buyback of Harris and Mayo generation from the NCEMPA.

In its filing, the Company made an adjustment to levelize the purchased capacity cost portion of the buyback of power from the Harris and Mayo units from NCEMPA. The levelization period used by the Company was the remaining life of the buyback for Mayo and ten years from the commercial operation date for the Harris Plant. No intervenor took exception to the levelization periods filed by the Company.

The Company's levelization calculation used a system composite state income tax rate of 7 percent. Commission Staff witness Price adjusted the levelization calculation to reflect the South Carolina state income tax rate of 5.5 percent.

Based solely on the evidence presented in this proceeding, the Commission believes that the proper levelization period for Mayo is the remaining life of the contract; and the proper levelization period for Harris is ten years beginning with the commercial operation date of the Harris Plant. Additionally, the levelization calculation should reflect the current South Carolina state income tax rate of 5.5 percent. Also, the difference between the levelized costs and the Company's actual Harris and Mayo purchased capacity payments should be placed in a deferred account and should accrue a return based upon the overall net-of-tax rate of return approved by the Commission in this proceeding. The Commission also believes that it would be appropriate to true-up this deferral account at the end of the levelization periods.

The next area of difference between the Company and the Consumer Advocate relates to the year-end payroll adjustment. In its filing, the Company included an adjustment to O&M expenses to reflect payroll expenses at the test year-end level. This adjustment increased O&M expenses by $214,540. The Commission Staff accepted the Company's adjustment. Consumer Advocate witness Miller testified that he agreed with the Company's adjustment in concept but recommended that no adjustment be made in this case for year-end payroll. Witness Miller testified that the Company annualized the payroll expense by using the number of employees at the end of the test period. He further testified

that this was inappropriate in this instance because the September 1987 employee level was higher than in any period between October 1986 and February 1988. If the September level of employees is used, the ratepayers will be forced to bear labor-costs that the Company is not incurring.

On cross-examination, Company witness Bradshaw stated that the Company's actual payroll for the 12 months ended May 1988 was higher than the annualized year-end payroll adjustment the Company included in this rate case. He testified that with the Company's requested annualized September 1987 payroll, the payroll expense was not up to the current level of the ongoing expense.

After considering all the evidence presented on this issue, the Commission concludes that the Company's year-end payroll adjustment is consistent with the methodology adopted by this Commission in prior rate cases and is appropriate for this proceeding. Therefore, it rejects the Consumer Advocate's proposal.

The next difference between the Company and the Consumer Advocate concerns Edison Electric Institute (EEI) dues. Included in the Company's test year expenses is $45,627 related to EEI dues. The Commission Staff made no adjustment to exclude this expense. Consumer Advocate witness Miller testified that EEI dues should not be included in operating expenses for ratemaking purposes unless they result in some direct and primary benefit to

consumers. He based his assertion on the fact that a number of EEI activities, including EEI's charitable contributions, memberships in social and service club organizations, donations, and advertising expenses, do not provide a primary benefit to consumers. He acknowledged that the Company had already excluded approximately two percent of EEI dues from test year expenses requested in this case. (TR. Vol. 15 at 199-203)

The Company maintains that only the portion of EEI dues that is charged below the line should be removed for establishing its allowable level of expense. Only two percent of EEI's total budget is spent on direct lobbying expenses according to EEI reports. The Commission agrees with the Company and finds that the Consumer Advocate's adjustment should be rejected.

The Consumer Advocate also made an adjustment to remove the test year expenses related to the Media Communications Fund (MCF). Witness Miller testified that based on his review of the 1984, 1985, and 1986 NARUC EEI oversight committee report, $5.8 million was spent for national advertising in 1986. He testified that it was his experience that this type of national advertising provides no direct and primary benefit to ratepayers. He also stated that because MCF advertising was national advertising, he could not understand how it could provide any direct and primary benefits to the Company's customers. (TR. Vol. 14 at 204-05)

After reviewing the evidence on this issue, the Commission has determined that the Consumer Advocate's adjustment should be

accepted. This adjustment is appropriate because the Commission has traditionally eliminated charges to the Media Communications Funds.

Another area of disagreement between the Company and the Consumer Advocate is legal fees related to a United Mine Workers Association (UMWA) lawsuit and an antitrust suit filed by the North Carolina Electric Membership Corporation (NCEMC) and 16 of its 18 members who receive wholesale service from the Company.

Consumer Advocate witness Miller recommended eliminating $28,616 from O&M expenses ($14,310 for the UMWA and $14,306 for the antitrust lawsuit). Mr. Miller's basis for elimination of the UMWA expenses was that the Commission had previously determined that the Company should not be permitted to recover losses associated with the Leslie and McInnes coal mines. He further stated that the expenses for the antitrust case should be excluded for ratemaking purposes, and the defense of the Company's actions is the responsibility of the stockholders and not the ratepayers. (TR. Vol. 14 at 195-98)

Company witness Bradshaw stated on cross-examination that the Company has an obligation to its customers to defend itself against any lawsuit that is filed against the Company. He testified that the costs to the ratepayer could be much greater if the Company did not defend itself against these types of lawsuits.

After reviewing the evidence on this issue, the Commission concludes that the Consumer Advocate's adjustment to eliminate legal fees associated with the UMWA and antitrust lawsuits should be rejected. The Commission believes that the Company had an obligation to the ratepayers as well as the shareholders to defend itself against these lawsuits.

Another area of disagreement between the Company and the Consumer Advocate relates to an uncollectible expense adjustment made by witness Miller. Witness Miller recommended that net write-offs for calendar year 1986 be used instead of the test year uncollectible expense because the test year expense level is abnormally high as a result of the Company's revised customer deposit policy. Between 1986 and 1987, gross write-offs increased by approximately $1.3 million. This increase was due to an increased level of customer kWh sales, increased revenues billed, and the Company's revised customer deposit policy.

Witness Miller reduced test year O&M expenses by $24,248 to reflect the calendar year 1986 level of net write-offs. He stated that the Company's revised customer deposit policy works to the detriment of the majority of the ratepayers and recommended that the Commission instruct the Company to abandon this new customer deposit policy. (TR. Vol. 14 at 177-78) The Commission Staff did not adjust the amount included in the test year for uncollectible accounts.

On November 3, 1986, the Company informed this Commission of the change in its customer deposit policy. The Company stated in its letter of notification that this modification was to reflect the Company's ongoing commitment to provide high quality service as well as to address the specific needs of its customers. The Commission finds that the Company's deposit policy is within the Commission's Rules and Regulations and benefits given to the customers far outweigh the costs. Therefore, the Consumer Advocate's adjustment is rejected.

Another area of disagreement between the Company and the Consumer Advocate is the Company's participation in the Nuclear Electric Insurance Limited (NEIL).

The Company is a member of NEIL which provides insurance coverage against incremental costs of replacement power resulting from prolonged accidental outages of members' nuclear generating units. NEIL is a utility industry-sponsored mutual insurance company.

Consumer Advocate witness Miller recommended that the Commission order the Company to produce NEIL's books and records and to have the Commission Staff conduct an audit. (TR. Vol. 14 at 194) A similar recommendation was made in CP&L's last general rate case, Docket No. 87-7-E. In that case, the Report of the Ad Hoc Committee on Insurance published by the National Association of Regulatory Utility Commissioners on March 4, 1987 was entered into evidence. The Commission takes judicial notice of this

report which discussed the use of industry mutuals for nuclear coverage and the report states "There is no reason for regulators to be suspicious that the premiums charged by industry mutuals are unreasonably high relative to the Market. Indeed, over the long run, industry mutuals may be able to better furnish public utilities with the coverages they need at the same reasonable costs."

No new evidence was provided in this proceeding to convince the Commission that it is necessary to order an audit of NEIL. Therefore, the Commission again rejects the Consumer Advocate's recommendation.

Based on the foregoing, the appropriate amount of total O&M expense for inclusion in rates in this proceeding is $177,254,000.

The next area of disagreement relates to depreciation expense. Company witness Bradshaw presented testimony and exhibits supporting a change in CP&L's depreciation rates. The recommended change in depreciation rates is summarized below:

	Current Rates	Proposed Rates
Production		
Steam	3.689	3.428
Nuclear	4.016	3.195
Hydro	1.170	1.414
Other	4.062	3.759
Transmission	2.376	2.699
Distribution	3.273	3.725
General	5.178	4.951

Company witness Bradshaw testified that the proposed depreciation rates include a component for removal cost, salvage, and ten years of interim activity. The life of the property for depreciation purposes was based on an actuarial methodology for non-production properties, consisting of Transmission, Distribution, and General properties. Life estimates utilizing industry averages were used for Hydro property and Internal Combustion Turbines. The life span methodology was used for production properties, consisting of Fossil Steam and Nuclear. Witness Bradshaw stated that the life span methodology allows for the evaluation of all factors affecting capital recovery by site location rather than by account. He explained that the items analyzed for each plant/unit were current plant investment; current accumulated depreciation; and projected additions, retirements, and replacements.

Fossil Steam Production property was grouped into one of three categories in order to establish remaining lives as a group.

These three categories were based on capacity factors that incorporate future operating plans for the Fossil Steam units into a realistic estimated remaining service life for each unit. Group I property consists of units that would be operating at a capacity factor above 50-60 percent. A remaining life of 28 years was assigned to units in this group except for the two newest units, which were assigned a 33-year remaining life.

Group II property consists of units that would be operating at a capacity factor above 10-20 percent but below 50-60 percent. A remaining life of 18 years was assigned to the units in this group. Group III property consists of units that would be operating at a capacity factor below 10-20 percent. A remaining life of seven years was assigned to the units in this group such that 95 percent of the depreciable investment would be recovered over the next seven years. Witness Bradshaw testified that due to the uncertainty of running the Group III units with such low capacity factors, there is a real need to have the majority of the capital investment recovered from these units in the near future. When considering all three groups, the age of each plant/unit plus its estimated remaining life, on average, is equal to a 40-42 year average life span.

The life of Nuclear Production property was also based on the life span methodogy. Witness Bradshaw testified that the trend in the electric utility industry is to utilize the Nuclear Operating License when establishing operating lives for capital recovery purposes. Therefore, the Company's basis for establishing a remaining life for each nuclear unit was each unit's license expiration date as adjusted to reflect the Company's request for revised operating licenses for Brunswick Unit Nos. 1 and 2 and Robinson Unit No. 2. Witness Bradshaw testified that, due to the uncertainty of future regulations and infancy of the nuclear industry, he was recommending that Nuclear

Production property depreciation rates be set such that 95 percent of the depreciable investment be recovered approximately five years prior to the expiration of the Nuclear Operating License. He further testified that as each unit approaches the license expiration date, an economic analysis would be performed to determine the cost/benefit of additional investment for continued operation as compared to the cost of shutting down the plant.

There was no disagreement on the proposed depreciation rates between the parties for Non-Production property, Hydro Production property, and Internal Combustion Turbines; therefore, the Company's proposed depreciation rates for these properties are approved.

Consumer Advocate witness Miller only took exception to one portion of the Company's filed depreciation study. Witness Miller's exception related to the seven-year remaining life for Group III Fossil Steam Production property. He testified that in his opinion the seven-year lives were too speculative to be used to develop the remaining lives for Group III Fossil Steam Production property. He contended that the seven-year period is not known with enough specificity to be used in this case. He recommended that the Company monitor the situation and develop the remaining lives when the data is more known and measurable. Witness Miller recommended that the Commission approve the old rate for Group III Fossil Steam Production property and approve

the new rates for Group I and Group II production properties. (TR. Vol. 14 at 190-93)

Company witness Bradshaw testified that an average life span for Fossil Steam Production property is 40-42 years. Group III Fossil Steam Production property assuming 95 percent recovery results in an average life span of slightly more than 40 years, which is within the industry average life span for Fossil Steam Production property. Witness Bradshaw further stated on cross-examination that most companies in the industry use a 40-year life for this type of property and that the Company's recommended depreciation rates for Fossil Steam Production property as a group were slightly longer than the 40-year period.

Commission Staff witness Sheely testified on cross-examination that he believed witness Miller's adjustment was inappropriate and as these were base load plants which are being used for cycling which can shorten plant life considerably. He recommended that the rates proposed by the Company be approved. (TR. Vol. 19 at 195)

The Commission finds that the remaining lives for Fossil Steam Production property should be considered in total and not separated by individual groups. As testified to by Company witness Bradshaw, Fossil Steam Production property has an estimated life of slightly longer than 40 years, which is consistent with the industry average depreciation life span. Therefore, the Commission rejects the Consumer Advocate's

recommendation and finds that the depreciation rate for Fossil Steam Production property is 3.428 percent.

Commission Staff witness Sheely testified that the Company's depreciation study was well done and, with one exception, he recommended to the Commission that the Company's filed depreciation study be approved. The one exception was the Company's depreciation study related to the proper depreciation rate for Nuclear Production property. Witness Sheely testified that the Nuclear Production Property Depreciation rate should be based on a straight line depreciation rate which fully depreciates the value of a facility at the end of its operating license. He stated that the straight line depreciation method was a widely accepted method and had historically been accepted in this jurisdiction and should be approved in this proceeding. The Nuclear Production Property Depreciation rate recommended by witness Sheely is 2.85301 percent.

For purposes of this proceeding, the Commission finds that the proper decpreciation rate for Nuclear Production property is 2.85301 percent as proposed by Staff. Appendix A sets forth the approved depreciation rates by component.

Company's adjustment to depreciation expense to reflect the year-end level of depreciation and inclusion of Harris Unit No. 1 depreciation is approved as adjusted by Staff for Nuclear Production Rates.

Other depreciation differences between the Company and the Commission Staff not related to the change in depreciation rates include: Non-Revenue Producing Plant, Robinson Dry Storage, and AFUDC on Harris Non-Project Land. Each of these items was discussed in other Findings of Fact, and the Commission Staff's position was adopted for each item. As discussed in this Finding of Fact, the Company's depreciation rates as adjusted by Staff for Nuclear Production were adopted and therefore should be used to calculate the depreciation expense associated with plant adjustments.

Based on the foregoing, the total allowable depreciation expense is $36,048,000.

Commission Staff witness Sheely also made an adjustment to depreciation expense based on the Staff's recommendation concerning the Harris Plant. As discussed earlier in Finding of Fact No. 7, the Commission accepted the Staff adjustment to treat a portion of Harris as abandoned plant; and therefore the related depreciation expense adjustment is accepted.

An issue related to depreciation expense is the amount of nuclear decommissioning costs to include in expenses. Company witness LaGuardia presented testimony supporting decommissioning estimates for the Brunswick, Robinson, and Harris nuclear units. Mr. LaGuardia's testimony reflected in mid-1987 dollars the cost to decommission the Company's nuclear units under two decommissioning processes: (1) prompt/removal dismantlement and

(2) entombment/30-year delayed dismantlement. Included in both decommissioning cost estimates was a 25 percent contingency allowance. He testified that the purpose of the contingency is to allow for the costs of high probability program problems where the occurrence, duration, and severity cannot be accurately predicted and have not been included in the basic estimate.

Based on the evidence presented in this case, the Commission finds that the decommissioning estimates, including a 25 percent contingency factor, were reasonable and should be approved.

Company witness Bradshaw presented testimony supporting the depreciation provisions necessary to recover decommissioning costs for the Company's four nuclear units. Witness Bradshaw stated that, consistent with Commission approval in Docket No. 81-163-E, the Company is recommending the entombment with dismantling after a 30-year delay decommissioning process updated to mid-1987 price levels by Mr. LaGuardia. He stated that the entombed property will not require significant maintenance for 30 years, thus the 30-year delay option will allow taking advantage of the "state of the art" developed by other utilities which will have decommissioned units during the 30-year dormancy period. He also stated that the delay period will result in decreased exposure of personnel to radiation.

Company witness Bradshaw also presented testimony and exhibits supporting the modified internal sinking fund capital

recovery methodology as approved by this Commission in Docket No. 81-163-E and requested again in this proceeding.

Commission Staff witness Sheely testified that he reviewed the report of Company witness LaGuardia and considered it reasonable and in line with decommissioning studies approved by this Commission for CP&L in previous cases and other jurisdictional utilities. Commission Staff witness Sheely recommended that the Company's decommissioning methodology as filed be accepted for ratemaking purposes in this proceeding. No other intervenor filed testimony on decommissioning in this proceeding. Therefore, the Commission finds that the Company's site-specific decommissioning estimate, including a 25 percent contingency factor and the internal modified sinking fund capital recovery method, is appropriate for use in this proceeding and is hereby adopted. The Company's jurisdictional decommissioning expense approved for use in this proceeding is therefore $1,314,000.

The next area of disagreement relates to the Commission Staff's adjustment to decrease property taxes in conjunction with the Staff's adjustment to eliminate AFUDC on Harris non-project land included in Plant In Service. In Finding of Fact No. 11, the Commission determined that the Staff's adjustment was appropriate; therefore, the Commission also approves this adjustment.

The next area of disagreement relates to current income tax expense. Many of the contested revenue and expense adjustments, as well as rate base adjustments, will have an income tax effect and therefore require no explanation. The appropriate income tax expense for inclusion in operating revenue deductions is calculated using a 34 percent federal income tax rate and a 5.5 percent state income tax rate.

The Commission Staff adjusted the Company's deferred income tax expense (DIT) and investment tax credit (ITC) to reflect the depreciation rate for the Harris Plant recommended by Staff witness Sheely. Therefore, the Commission accepts this Staff's adjustment to DIT and ITC.

Further, the Commission will adjust DIT and ITC to reflect its treatment of the Harris Plant expenditure set forth in Finding of Fact No. 7.

The last operating revenue deduction item for discussion is the Harris deferred costs. The Company proposed in this case to begin to recover all Harris Plant costs deferred during the period May 2, 1987 to August 26, 1987 and costs for the 50 percent of the plant not included in rates on August 26, 1987 for the period ended August 26, 1987 through July 1988. The Company proposed that these deferred costs be amortized over 104 months which would allow the Company to recover these costs within ten years of the date of commercial operation of the Harris Plant in

compliance with the requirements of Financial Accounting Standards Board Statement No. 92 (FASB No. 92).

The Commission accepts the Commission Staff adjustment to the Harris deferral to reflect the state income tax rate of 5.5 percent and to reflect the deferral to the date of the order in this case. Also, the Commission will adjust the Harris deferral to reflect the 5.5 percent state income tax rate for that portion of the Harris Plant treated in Finding of Fact No. 7. The Commission previously determined that the South Carolina state income tax rate of 5.5 percent should be used in calculating the Harris deferral. Therefore, the amortization of the Harris deferral appropriate for use in these proceedings is $5,125,000. Finally, no party contested the amortization period for the Harris deferral; and therefore the Harris deferral is to be amortized over ten years from the commercial operation date of the Harris Plant. The Commission also believes that it is appropriate to true-up this deferral account in a subsequent general rate case.

The Commission has considered all other adjustments to, or treatment of, revenues, expenses or rate base items proposed by the Staff in its presentation, not specifically addressed herein, and have found the adjustments fair and reasonable and adopted same for purposes of this proceeding as allocated to Company's South Carolina Retail operations pursuant to Staff's methodology. All other adjustments proposed by any party inconsistent

therewith have been reviewed and found to be unreasonable or inappropriate for ratemaking purposes and are hereby denied.

The Commission hereby will adjust general taxes, state and federal income taxes, to reflect all adjustments herein approved.

The following chart summarizes the South Carolina retail operating revenue deductions adopted in this Finding of Fact:

Item	Amount ($000s)
O&M	177,254
Depreciation Expense	36,048
Taxes, Other Than Income	10,984
Current Income Taxes	13,821
Deferred Income Taxes	9,259
Investment Tax Credit	2,100
Interest on Customer Deposits	109
Harris Deferral (Net of Tax)	5,125
Total Operating Revenue Deductions	254,700

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 9

Capital Structure

The evidence for this finding concerning the appropriate capital structure and rate of return is found primarily in the testimony and exhibits presented by Company witnesses Bradshaw and Vander Weide, Staff witnesses Price and Rhyne, and Consumer Advocate witness Legler.

Company witnesses Bradshaw and Vander Weide recommended that the pro forma capital structure through April 1988 proposed by the Company be approved by this Commission as most representative for CP&L. The following chart summarizes the positions of the

parties regarding the appropriate capital structure for use in this proceeding:

	Company	Commission Staff	Consumer Advocate
Long-term Debt	47.50%	47.82%	47.82%
Preferred Stock	7.30%	7.46%	7.46%
Common Equity	45.20%	44.72%	44.72%
TOTAL	100.00%	100.00%	100.00%

In its Application, as reflected in the prefiled testimony and exhibits of Company witnesses Bradshaw and Vander Weide, the Company utilized a pro forma capital structure estimated by adjusting the September 30, 1987 actual capital structure for changes anticipated to occur through April 1988. This capital structure included a 45.20 percent common equity ratio.

Consumer Advocate witness Legler recommended that the Commission adopt the actual capital structure of the Company at the time the Commission prepares its decision. Dr. Legler's prefiled testimony contained a capital structure based on the Company's actual March 31, 1988 capital structure. Dr. Legler testified that a 45 percent equity ratio is about average for a Single A-rated electric utility at the present time. (TR. Vol. 14 at 94)

Company witness Bradshaw presented the actual capital structure and cost rates through May 1988. (TR. Vol. 3 at 125)

This capital structure is consistent with the Company's request to use a normalized capital structure. The actual May 1988 capital structure and embedded cost rates are as follows:

	%	Cost Rates
Long-term Debt	47.50%	8.69%
Preferred Stock	7.40%	8.75%
Common Equity	45.10%	-
TOTAL	100.00%	-

Based on the evidence presented in this case, the Commission finds that the capital structure proposed by the Consumer Advocate and the Commission Staff is appropriate for establishing an overall rate of return for the Company.

Accordingly, the Commission finds and concludes that the reasonable and appropriate capital structure for CP&L in this proceeding is a capital structure as follows:

Item	Percent
Long-term Debt	47.82%
Preferred Stock	7.46%
Common Equity	44.72%
TOTAL	100.00%

Regarding the cost rates for long-term debt and preferred stock, the parties filed as follows:

	Company	Commission Staff	Consumer Advocate
Long-term Debt	8.73%	8.62%	8.62%
Preferred Stock	8.75%	8.75%	8.75%

Company witness Bradshaw presented the actual embedded cost rates at May 1988 of 8.69 percent for long-term debt and 8.75 percent for preferred stock.

Based on the evidence presented, the Commission concludes that the appropriate embedded cost rates of long-term debt and preferred stock to be used in this proceeding are the actual embedded cost rates at March 31, 1988 of 8.62 percent and 8.75 percent, respectively, as proposed by the Consumer Advocate and Commission Staff.

The testimony and exhibits of the financial witnesses for the Company, the Commission Staff and the Consumer Advocate demonstrated an approach to their respective investigations of the cost of common equity of CP&L within the parameters of the language of the United States Supreme Court in its decision in Federal Power Commission vs. Hope Natural Gas Co., 320 U.S. 591 (1944), at 603:

> [T]he return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attact capital.

The United States Supreme Court's landmark decision in Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia, 262 U.S. 679 (1923), delineated

general guidelines for determining the fair rate of return in utility regulation. In the Bluefield decision, the Court stated:

> What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risk and uncertainties; but it has no constitutional rights to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business generally.
>
> 262 U.S. at 692-693.

During the subsequent year, the Supreme Court refined its appraisal of regulatory precepts. In its frequently cited Hope decision, supra, the Court restated its view:

> We held in Federal Power Commission v. Natural Pipeline Gas Co....that the Commission was not bound to the use of any single formula or combination of formulae in determining its rates. Its ratemaking function, moreover involves the making of 'pragmatic adjustments' (cite omitted).... Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed which is controlling (Citation omitted)....

> The ratemaking process under the Act, i.e., the fixing of 'just and reasonable' rates involves a balancing of the investor and the consumer interests. Thus we stated in the Natural Gas Pipeline Co. case, that regulation does not insure that the business shall produce net revenues. (Citations omitted).
>
> But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. (Citation omitted). By that standard the return to the equity owner should be commensurate with returns on investments in other enterpises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attact capital.
>
> 320 U.S. at 602-603.

The vitality of these decisions has not been eroded, as indicated by the language of the more recent decision of the Supreme Court in IN RE: Permian Basin Area Rate Cases, 390 U.S. 747 (1968). This Commission has consistently operated within the guidelines set forth in the Hope decision.

The cost of common equity is an estimate and necessarily involves judgment in its determination. (Tr., Vol. 1, Vande Weide, at 97.) In most cases, and this case is no exception, the cost of common equity is the most controversial aspect of the cost of capital. The estimates of the appropriate cost of common equity to be applied in this case range from 12.25%, the bottom end of the broad range provided by Staff witness Rhyne to 13.5% the estimate of Dr. Vander Weide, the Company's witness. The

cost of equity of 12.75% approximates the midpoint of Dr. Rhyne's broad range of estimates and is at the lower end of his best point estimate. It is the point estimate recommended by Dr. Legler. (Tr., Vol. 20, Rhyne, at 97.)

The legal criteria for determining the overall cost of capital and by implication the important component of common equity, are stated in the Hope and Bluefield decisions. All of the cost of capital witnesses adopted the mandates of these decisions as the criteria for judging the reasonableness of their recommended return and their recommendations must be judged in the context of these legal criteria. (Tr., Vol. 1, Vander Weide, at 98.) Although differences in emphasis on specific methodology were present in the testimonies, the witnesses recognized and relied on several methodologies to arrive at their ultimate recommendations on the cost of common equity. Indeed, several financial models were used by the witnesses. Important differences among the models as applied as well as the assumptions adopted by the witnesses must be evaluated since these differences are at the heart of the spread in their recommendations.

In reality, the spread in the cost of equity estimates of the three cost of capital witnesses in this case is relatively small. The spread between the 12.75% recommendation of Drs. Rhyne and Legler and the 13.5% of Company witness Vander Weide is only 75 basis points. Much of the variation in the estimates

based on the discounted cash flow method may be attributed to the treatment of issuance costs on new stock issues. Much of the discussion of the cost of equity in this section will focus on considerations of the issuance expense issue.

The Company's cost of capital witness, Dr. Vander Weide, employed two basic techniques for estimating the cost of equity: (1) the discounted cash flow model, and (2) the risk premium method. (Tr., Vol. 1, Vander Weide, at 63.) Staff witness Rhyne relied on the discounted cash flow (DCF) approach and the Capital Asset Pricing Model. (Tr., Vol. 20, Rhyne, at 54-55.) Dr. Legler, the Department of Consumer Affairs witness, placed primary reliance on the discounted cash flow (DCF) approach, supporting his recommendation with a risk premium analysis and a review of earned returns of comparable electrics. (Tr., Vol. 14, Legler, at 86.) All three of the cost of capital witnesses applied the discounted cash flow method to company specific data for Carolina Power & Light and selected groups of other electric utilities.

The discounted cash flow results derived by Dr. Vander Weide for CP&L and a group of comparable companies in his prefiled testimony was 12.40 percent and 13.40 percent, respectively. At the time of the hearings, Dr. Vander Weide updated his DCF results producing a cost of common equity capital of 12.3 percent for CP&L and 13.30 percent for the group of companies. These estimates included adjustments for the issuance cost of common

equity. Dr. Rhyne recommended a cost of common equity between 12.75 percent and 13.00 percent and Dr. Legler recommended a best point estimate of 12.75% based on their DCF studies and supporting methodologies. The recommendations of Drs. Rhyne and Legler did not include adjustment for issuance costs.

Dr. Vander Weide's version of the DCF model explicitly provides for an issuance cost adjustment. This is accomplished by adjusting the price variable in the DCF model. Dr. Vander Weide used a 5% adjustment factor which includes 3% for issuance costs and 2% for market pressure. But as discussed in Dr. Legler's testimony the market pressure component is transitory and not necessarily positive. Dr. Rhyne did not include a market pressure component within his methodology for deriving an issuance cost adjustment.

Dr. Vander Weide's approach to the issuance cost adjustment basically amounts to providing an equity return on the Company's accumulated issuance expense during roughly the last forty years. (Tr., Vol. 2, Vande Weide, at 25-30.) Essentially, this treats the accumulated issuance costs as a perpetual equity investment. Thus, Dr. Vander Weide is of the opinion that whether or not the Company intends to issue common stock in the future is irrelevant. The Commission believes that Dr. Vander Weide's approach is inappropriate for several reasons.

First, Dr. Vander Weide's approach assumes that the Commission has never provided any recovery for issuance costs. There is no documentation to support this claim.

Second, Dr. Vander Weide's approach assumes that market pressure was present on all past issues. As shown in Dr. Legler's Schedule 15 (Hearing Exhibit 119), such is not the case. Therefore, it is the opinion of this Commission that Dr. Vander Weide's adjustment for market pressure is unsupportable and inappropriate.

Dr. Rhyne (TR., Vol. 20, Rhyne at 68) set forth the basis for his approach for considering issuance costs within his testimony. Dr. Rhyne stated:

> "This approach is applied where one is seeking to allow a utility to recover reasonable issuance expenses related to a specific issuance of common stock. Under this approach, if a utility has recently issued common stock or has plans to issue additional common stock during the time period in which the rates resulting from the case are expected to be in effect, an adjustment would be appropriate to recover issuance expenses."

The Company has no plans to issue common equity in the near future (TR., Vol. 20, Rhyne at 69). Therefore, an issuance cost adjustment in this case would be inappropriate.

The Company's witness, Dr. Vander Weide, also relied on a risk premium approach. Essentially, he estimated a long term historical risk premium as the spread in returns between common stocks as represented by the S&P 500 stock index and Moody's single A-rated utility bond portfolio. He found this spread to

be 5.92%. He repeated the study using the S&P 40 Utilities and found an average spread of 4.66%.

It is this Commission's position that risk premiums do change over time in response to institutional and other factors. Dr. Vander Weide's own testimony (Tr., Vol. 1, Vande Weide, at 79-80) indicates this. It is this Commission's position that there is no support for the proposition that risk premiums measured over the longest time period possible are to be preferred to any other time period. Risk premiums appear to be inversely related to the level of interest rates. (Tr., Vol. 1, Vander Weide, at 83.) Implicitly, this suggests that the cost of equity is more stable than interest rates. The Commission believes that Dr. Vander Weide's estimate of the cost of equity does not adequately account for this factor and overstates the expected risk premium.

Based on his own studies and those of others he cites, Dr. Vander Weide concluded that the risk premium was 4 to 5 percentage points which he added to the long term interest rate on single A-rated utility bonds. At the time he prepared his testimony this rate was 11%. Accordingly, Dr. Vander Weide's risk premium analysis resulted in an estimated cost of equity in a range of 15% to 16%. At the time of the hearing, Dr. Vander Weide's risk premium results were in the range of 14 percent to 15 percent. The Commission feels that the risk premium employed

in the study by Dr. Vander Weide leads to results which overstate the cost of common equity.

In summary, this Commission believes that adoption of a recommended return on common equity of 12.75% would enable CP&L to maintain its financial integrity, attract capital required on reasonable terms, fairly balance consumer and investor interests, and provide a return comparable to that available to companies of comparable risk. Therefore, it is this Commission's position that 12.75% conforms to the mandates of Hope and Bluefield. With respect to CP&L's requested return on common equity of 13.5%, it is this Commission's position that it is excessive and is unacceptable for reasons set forth herein. There is not a large disparity in the cost of common equity estimates resulting from the discounted cash flow method, a method supported by all three cost of capital witnesses as an appropriate method for estimating the cost of common equity. The Commission believes the risk-premium approach as applied by Dr. Vander Weide overstates the cost of common equity. It is the Commission's position that the assumptions adopted by Dr. Rhyne in the application of his methods are reasonable. The Commission finds that Dr. Rhyne's conclusions are supported by the studies of Dr. Legler. Accordingly, this Commission adopts the cost of common equity recommended by Drs. Rhyne and Legler, i.e. 12.75%.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 10

The evidence for this finding concerning the appropriate level of Working Capital can be found in the testimony and exhibits of Company witnesses Nevil and Bradshaw, Commission Staff witness Price, and Consumer Advocate witness Miller.

The Commission Staff's elements of working capital allowance and materials and supplies are presented in the table below:

	($000s)
Materials and Supplies	16,990
Working Capital Allowance	
Base Working Capital Allowance	17,741
Add: Minimum Bank Balances	383
Prepayments	5,983
Less: Average Tax Accruals	(6,811)
Operating Reserves	(503)
Accounts Payable Included in Plant	(2,023)
Nuclear Mutual Limited Reserve	(1,265)
Unclaimed Funds	(112)
Customer Advances for Construction	(224)
Total Working Capital Allowance	13,169
Total Materials and Supplies and Working Capital Allowance	30,159

The first area of disagreement related to proper level of coal inventory. CP&L witness Nevil recommended that coal inventory be established at an 80-day supply level. Commission Staff witness Price used the maximum draw-down method to calculate an appropriate level of coal inventory. Consumer Advocate witness Miller testified that he disagreed with the Company's calculation of the 80-day supply because it is too speculative when consideration is given to the changes in the

Company's operations such as Harris coming on line, the NCEMPA buyback, purchased power, and cogeneration. He also stated that the Company was not maintaining an 80-day inventory and should not be allowed to earn a return on a level of rate base which reflects an 80-day inventory. (TR. Vol. 14 at 151-54)

The Commission notes that the inclusion of Harris as a generating unit has reduced the average daily coal burn for the Company. This is indicated in the Company's workpapers which show the test year average daily burn being reduced by approximately 2,300 tons per day by annualizing Harris generation. The Company and Commission Staff both used the same burn of 22,157 tons per day in arriving at their respective inventory levels.

The Commission Staff's recommended maximum draw-down method yields a 77.2-day inventory level compared to the Company's proposal of an 80-day supply. It is important that the Company maintain an adequate inventory level to ensure system reliability. The difference in the Company's and the Staff's recommendation is less than three days' supply of coal.

The Commission concludes that the Staff's proposal which was accepted in the last CP&L rate case and other prior rate cases should be approved.

The next area of disagreement relates to two Commission Staff adjustments to the calculation of the working capital allowance.

First, the Commission Staff proposed an adjustment which would reduce Working Capital Allowance by approximately $224,000 to reflect the availability to the Company of Unclaimed Funds. The Company did not contest this Staff adjustment, and the Commission therefore adopts the Staff adjustment.

Second, the Company and the Commission Staff disagreed about whether working capital treatment should be permitted for the Robinson Dry Storage demonstration program. In its filing, the Company included, as a component of working capital, $144,000 for the expenses it has incurred for this program. The purpose of this program is to make dry storage of spent fuel in concrete silos a licensable option and prove that the concept is a low-cost, safe, and environmentally sound storage alternative.

The Commission Staff eliminated this item as a component of working capital. The Commission adopts the Staff's adjustment.

The Company calculated a cash allowance using the one-eighth formula consistent with the Commission's directive and with Commission findings in prior cases. Commission Staff witness Price also supported the continued use of the one-eighth formula. Consumer Advocate witness Miller recommended the use of a lead/lag study modified to exclude non-cash items. After consideration of the evidence, the Commission is of the opinion that the one-eighth formula continues to be the appropriate method for calculating the allowance for cash working capital.

The next issue involves the appropriate level of customer deposits to use in the cost of service. The Company deducted Customer Deposits from rate base using the per book balance at the end of the test year consistent with the Commission treatment in prior rate orders.

Commission Staff witness Price also deducted Customer Deposits from rate base using the per book balance at the end of the test year.

Consumer Advocate witness Miller recommended, in conjunction with his position regarding the Company's revised deposit plan, that the rate base deduction for customer deposits be based on a 13-month average for the period September 1986 through September 1987. He stated that by using a 13-month average, the full impact of the Company's revised policy will not be borne by the customers. His adjustment further reduces rate base by $138,351. (TR. Vol. 14 at 178-79)

The Commission, after considering all evidence on this issue, finds that the end-of-period balance, as reflected on the Company's books, is the most appropriate method to use in this case and therefore accepts the Company's and Staff's proposed amount.

The following table provides the appropriate values accepted by the Commission for the working capital allowance and materials and supplies:

Item	Amount ($000s)
Material & Supplies	16,990
Working Capital Allowance	13,169
Total	30,159

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 11

The evidence supporting these findings concerning the proper value for rate base is found in the testimony of Company witness Bradshaw, Staff witnesses Price and Watts, and Consumer Advocate witness Miller, as well as from Finding of Fact No. 7.

The differences between the Company and the Commission Staff concerning rate base items are presented in on the following table:

Item	Company ($000s)	Commission Staff ($000s)	Differences ($000s)
Plant in Service	1,119,226	1,086,241	(32,985)
Depreciation Reserve	(208,890)	(205,741)	3,149
Net Nuclear Fuel	28,758	28,758	0
Plant Held for Future Use	2,562	2,562	0
Accumulated Deferred Income Taxes	(107,070)	(106,580)	490
Materials & Supplies	17,398	16,990	(408)
Cash Working Capital	12,622	12,254	(368)
Total Rate Base	864,606	834,484	(30,122)

The first issue relates to an adjustment made by Commission Staff witness Price. Witness Price made an adjustment to reduce Plant in Service by $5,493,777 to eliminate the Robinson Waste Solidification System from plant in service. This project had

not been completed but was included in per books plant in service. The Company did not object to this adjustment of the Staff. Therefore, the Commission accepts the Commission Staff's adjustment.

Another area of disagreement relates to an adjustment the Company made to include non-revenue producing plant in Plant in Service. In its filing, the Company made an adjustment to increase Plant in Service for non-revenue producing plant projects that were anticipated to be completed by June 1988. This adjustment increased Plant in Service by $15,095,767. Commission Staff witness Watts agreed with the adjustment but recommended that only those projects which were actually closed at March 31, 1988 be included in Plant in Service. The Staff therefore recommended an adjustment to increase plant in service by only $8,674,925. (TR. Vol. 19 at 219)

Consumer Advocate witness Miller testified that the Company's adjustment reflects a projected amount that is not known and will not be known by the close of the hearings in this proceeding. He further stated that this adjustment actually constitutes an inclusion of construction work in progress and, as such, there should be some consideration of an AFUDC offset. (TR. Vol. 14 at 171-72).

Based on the evidence presented in this case, the Commission finds that the Commission Staff's adjustment is the proper amount to include in this proceeding.

Another area of disagreement between the Company and the Commission Staff relates to AFUDC on Harris non-project land that was included in Plant In Service as a cost of the Harris Plant. At the time land was purchased for the Harris Plant, the actual purchase price and associated overheads were recorded in Construction Work In Progress, using one expenditure requisition. As a result of the sale of a portion of Harris to the NCEMPA, the Company divided the Harris land into two expenditure requisitions so the land not directly associated with the Harris Project would be severed from the project. All AFUDC and associated overhead costs remained as a cost of the required Harris project land; therefore, the Company is reflecting AFUDC on the Harris non-project land in plant in service.

Commission Staff witness Watts made an adjustment to reduce plant in service by $1,032,128 to eliminate AFUDC and the associated overhead costs on the Harris non-project land included in Plant In Service.

The Company did not contest this adjustment; therefore, the Commission accepts the Staff's recommendation.

The final difference between the Company and the Commission Staff concerning Plant In Service relates to Staff witness Watts' adjustment of $20,038,179 to reflect the amortization of that portion of the Harris Plant that the Staff proposed be treated as abandoned plant. In light of the treatment adopted supra to the Harris Plant costs, the Staff's proposal here must be denied.

The Commission will remove from plant in service $440,000,000 for the entire Harris project or $52,556,000 on a South Carolina Retail Basis for the reasons set forth in Finding of Fact No. 7.

Consumer Advocate witness Miller recommended that the remaining portion of the Harris Plant, not yet included in rates, be phased in over a period not to exceed ten years, to mitigate rate shock. He testified that each year's increase should be limited to 5 percent. (TR. Vol. 14 at 138-40)

All of the differences between the Company and the Staff concerning the depreciation reserve were discussed in Finding of Fact No. 8 under the discussion of depreciation expense and therefore no further discussion is required here.

The difference between the Company and the Staff concerning the accumulated deferred income taxes (ADIT) relates to the Staff's adjustment for Harris Unit No. 1 abandonment and Staff's exception to the Nuclear Production Depreciation Rates. As discussed in Finding of Fact No. 7, the Commission has removed a portion of Harris Unit No. 1 from rate base and has accepted Staff's Nuclear Production Depreciation Rate; therefore, Staff's corresponding adjustment to ADIT is also accepted and a like adjustment will be made to reflect the Commission's treatment of the Harris Plant expenditures in Finding of Fact No. 7.

The differences between the Company and the Commission Staff relating to Materials and Supplies and Cash Working Capital were discussed in Finding of Fact No. 11.

Based upon the foregoing discussion, the following table provides the appropriate jurisdictional amounts for each rate base item as approved by the Commission:

Item	($000s)
Plant In Service	1,053,723
Depreciation Reserve	(204,888)
Net Nuclear Fuel	28,758
Plant Held for Future Use	2,562
Accumulated Deferred Income Taxes	(105,376)
Materials & Supplies	16,990
Working Capital Allowance	13,169
Customer Deposits	(915)
Total Rate Base	804,023

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 12

The Commission has previously discussed its findings of fact and conclusions regarding the fair rate of return which CP&L should be afforded an opportunity to earn.

The record in this proceeding demonstrates that the wholesale operations of the Company at the present time generate a lower rate of return than the overall rate of return for the various classes of jursidictional retail customers. The Commission herein repeats its interest in the Company's efforts to correct this situation, including the institution of ratemaking proceedings before the FERC. As the Commission has stated on several occasions in recent ratemaking proceedings involving its principal jurisdictional electric utilities, rates cannot, and will not, be approved which have the effect of

subsidizing non-jurisdictional operations through earnings derived from utility operations within the Commission's jurisdiction. It is the overall rate of return of the entire Company that a potential investor analyzes. To the extent that the Company fails to earn a proper return on its non-jurisdictional service, there is a direct, adverse impact on the retail customer. The Commission will expect the Company to continue to take all reasonable steps to correct this situation.

The following schedules summarize the gross revenues and the rates of return which the Company should have a reasonable opportunity to achieve based upon the determinations made herein. Such schedules, illustrating the Company's gross revenue requirements, incorporate the findings of fact and the conclusions made herein by the Commission. The approved increase shall be applied in like proportions to the proposed increase as per Staff recommendation.

SCHEDULE I
CAROLINA POWER & LIGHT COMPANY
DOCKET NO. 88-11-E
STATEMENT OF OPERATING INCOME
TWELVE MONTHS ENDED SEPTEMBER 30, 1987
(000'S OMITTED)

	Before Increase	Approved Increase	After Increase
Operating Revenues	322,664	24,980	347,644
Operating Expenses:			
Operating & Maintenance Expenses	177,254		177,254
Depreciation Expense	36,048		36,048
Taxes Other Than Income	10,984	75	11,059
State Income Taxes	3,291	1,370	4,661
Federal Income Taxes	10,530	8,002	18,532
Deferred Income Taxes	9,259		9,259
Deferred Investment Tax Credit	2,100		2,100
Interest on Customer Deposits	109		109
Total Operating Expenses	249,575	9,447	259,022
Net Operating Income	73,089	15,533	88,622
Add: Customer Growth	623	132	755
Deduct: Harris Deferral	5,125		5,125
Total Income for Return	68,587	15,665	84,252

SCHEDULE II
CAROLINA POWER & LIGHT COMPANY
SOUTH CAROLINA RETAIL OPERATIONS
DOCKET NO. 88-11-E
STATEMENT OF RATE BASE AND RATE OF RETURN
TWELVE MONTHS ENDED SEPTEMBER 30, 1987
(000'S OMITTED)

Item	Amount $
Investment in Electric Plant	
Electric Plant In Service	1,053,723
Net Nuclear Fuel	28,758
Accumulated Depreciation	(204,888)
Accumulated Deferred Income Taxes	(105,376)
Plant Held for Future Use	2,562
Net Investment in Electric Plant	774,779
Allowance for Working Capital	
Investor Funds Advanced for Operations	13,169
Materials and Supplies	16,990
Other Rate Base Additions and Reductions	(915)
Total	29,244
Original Cost Rate Base	804,023
Rate of Return	
Present	8.53%
Approved	10.48%

SCHEDULE III
CAROLINA POWER & LIGHT COMPANY
SOUTH CAROLINA RETAIL OPERATIONS
DOCKET NO. 88-11-E
STATEMENT OF CAPITALIZATION AND RELATED COSTS
TWELVE MONTHS ENDED SEPTEMBER 30, 1987
(000'S OMITTED)

Item	Capitalization Ratio (%)	Original Cost Rate Base ($)	Emedded Cost (%)	Net Operating Income ($)
	Present Rates - Original Cost Rate Base			
Long-Term Debt	47.82	384,522	8.62	33,146
Preferred Stock	7.46	59,954	8.75	5,246
Common Equity	44.72	359,547	8.40	30,195
Total	100.00	804,023		68,587
	Approved Rates - Original Cost Rate Base			
Long-Term Debt	47.82	384,522	8.62	33,146
Preferred Stock	7.46	59,954	8.75	5,246
Common Equity	44.72	359,547	12.75	45,860
Total	100.00	804,023		84,252

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 13

Evidence for this finding concerning rate design, rate schedules, and service regulations is found in the testimony and exhibits of Company witnesses Edge and Spann, Commission Staff witness Watts, South Carolina Department of Consumer Affairs witness Ileo, South Carolina Energy Users Committee witness Phillips, and Nucor witness Goins. Proposals of the parties in this proceeding are described below.

General Rate Design and Allocation of Revenues

CP&L witness Edge testified that the Company's rate design objective is to move toward uniform rates of return for all customer classes. Since class rates of return are continually changing as cost relationships and customer usage changes, the Company strives to design rates that result in a rate of return for each customer class that does not vary by more than 10 percent from the South Carolina retail rate of return. Based on the rate design proposed by the Company in this proceeding, all customer classes except the lighting class fall within this 10 percent range. To achieve the 10 percent objective, the Company proposed a higher-than-average increase for the Small General Service and Medium General Service rate schedules and a lower-than-average increase for the Large General Service rate schedule and the Residential and Lighting classes.

South Carolina Energy Users Committee witness Phillips recommended approval of a rate design which reduced existing

interclass variations from an equalized rate of return by approximately 50 percent. He further recommended allocating all increases relative to the Large General Service (LGS) rate schedules to the demand component, adjusting energy charges only for variations in fuel costs.

The Commission has reviewed the testimony involving the appropriate rate design and allocation of revenues among the rate classes. The Commission finds that the Company's approach is appropriate and therefore approved. This approach tends to encourage stability, reduce rate shock, and over time will result in more uniform rates of return among the classes and the rate schedules within those classes. The Commission concurs with the Company's proposal to minimize increases to the Lighting class revenue in this proceeding and to maintain this course of action until such time as the Lighting class rate of return reaches the overall retail rate of return.

Residential Class

The Company proposed a standard residential service schedule and two time-of-use schedules for its residential class. Miscellaneous charges applicable to the RES schedule include a 25-cent increase in the Basic Facilities Charge and an increase in the charge for three-phase service for all residential schedules to $9.00.

The Commission concludes that the increase in the charge for three phase service for all residential schedules is granted and

the increase in the basic facilities charge for the standard residential rate is denied.

The Company proposed the continuation of the two time-of-use rates for its residential customers in addition to the standard residential rate and standard residential rate with conservation reduction. Miscellaneous changes applicable to the two residential time-of-use rates (R-TOUD and R-TOUE) as well as to the standard residential rate included increasing the basic facilities charge by $0.25 and the three-phase service from $6.25 to $9.00. The Company also proposed changes in the R-TOUD and R-TOUE rate schedules to reflect the same percentage revenue increase as requested for the residential class. Additionally, the Company recommends seasonal pricing differentials for the R-TOUD schedule remain consistent with the pricing structure approved by this Commission in the prior general rate case.

CP&L witness Edge testified that the Company had implemented numerous enhancements to encourage its customers to participate in the TOU program. Those enhancements included a comparative billing program; introduction of the all-energy R-TOUE rate as approved by this Commission in CP&L's last rate case, Docket No. 87-7-E; more acceptable contract period provisions; inclusion of holidays to the off-peak period; inclusion on residential and SGS customer bills of monthly and annual cumulative savings derived from their participation in a TOU rate; and a TOU computer program designed to predict the potential savings a residential

customer may realize by switching to a TOU rate. In January 1987, the Company had 386 customers on its R-TOUD rate. By March, 1988, 1,425 customers were on the R-TOUD and R-TOUE rates, of which six were R-TOUE customers. Mr. Edge testified that promotion of time-of-use rates was a way to encourage the Company's customers to get full benefit from the use of their electricity at a lower cost. Additionally, it helps hold down the Company's future costs because they would not have to build as much plant in order to serve the load. In regard to the seasonal demand pricing differential contained in the R-TOUD rate schedule, witness Edge testified that the summer peak is the primary peak as far as customer usage, kW and kWh, was concerned. Consequently, the Company should signal to its customers, through rate designs, that the summer peak is the primary peak. This was accomplished by the Company charging a higher on-peak demand charge during the summer months than the remaining months in its R-TOUD rate schedule. The seasonal differential contained in the on-peak energy charges of the R-TOUE rate, as explained by witness Edge, was determined by rolling the demand charge and the on-peak energy charge of the R-TOUD rate into one on-peak rate for the R-TOUE schedule.

Consumer Advocate witness Ileo testified that the proposed increases in the R-TOUD and R-TOUE rates were significantly higher than the proposed increases for the standard residential energy rates. From this observation, he concluded that the

proposed residential time-of-use rates did not appear to be revenue neutral. (TR. Vol. 15 at 17) Ileo stated in his prefiled testimony that the R-TOUD and R-TOUE customer charge was a deterrent to time-of-use rate promotion and recommended that it not be increased and consideration should be given to reducing the charges. (TR. Vol. 15 at 19) He also recommended no seasonal differentiations be made in the demand charges for R-TOUD and in the energy charges for R-TOUE stating that the Company had not provided any seasonal costs differences in its filings. He further recommended the differential between the on-peak and off-peak energy charges for the R-TOUE rate be reduced. (TR. Vol. 15 at 22)

The Commission has reviewed the evidence and approves the rate design for R-TOUD and R-TOUE rates as filed except that no increase is granted for any basic facilities charge and demand and energy charges should be reduced to match class revenue allowed. The Commission finds these rates to be revenue neutral as they are based on the same level of revenue as the residential class. Recognizing that 94 percent of the R-TOUD customers will continue to save money by participating in this rate, the Commission approves the percentage rate increase required to meet the approved revenue increase. With the addition of more than 1,000 residential time-of-use customers in 15 months, the Commission recognizes the Company's efforts in the promotion of these rates. The Company is recommending seasonal pricing

differentials for the R-TOUD schedule consistent with the pricing structure previously approved by this Commission; therefore, the Commission approves the seasonal demand differential in the R-TOUD rate schedule. The Commission also recognizes that the R-TOUE seasonal on-peak differential is derived from the R-TOUD on-peak energy charges as well as the seasonal demand charges; and since previously approving the R-TOUD seasonal differential, the Commission likewise approves the R-TOUE seasonal on-peak energy differential. The Commission finds the energy differential for the R-TOUE rate to be appropriate and provides the proper incentive for R-TOUE customers to shift their usage into the off-peak periods.

General Service Class

The Company proposed seven active and two frozen schedules for its General Service class of customers. The withdrawal of frozen rate schedule RFS (Rural Farm Service) and the increase in rates applicable to schedules CSG (Church and School Service) and CSE (Church and School Service - All-Electric) by approximately 10 percent more than other schedules in order to gradually merge these schedules with the SGS/MGS/SI schedules over time is approved. As previously described, the late payment charge for general service customers and the Company's proposed changes to its three-block demand rate structure and transformation discounts for the LGS schedules are approved as filed. Other miscellaneous changes in the General Service class include an

increase in the charge for three-phase service to $9.00 in the SGS schedule; an increase in the basic facilities charge for the SGS Time-Of-Use schedule to $21.00, an increase in the kilowatt-hour charge in the Minimum Billing Provision of SGS-TOU to 2.130 cents per kilowatt-hour; and a change in the Contract Period provision in the SGS, SGS-TOU, and LGS schedules in this class to specify that construction or temporary service will be rendered in accordance with Plan E. The Company also proposed to modify the SGS-TOU and SGS-TES schedules to increase the rates and charges so that the schedules are revenue neutral when compared to the combined revenue received from the Small General Service, Medium General Service, and Seasonal or Intermittent Service customers. These proposed changes are approved as filed with the exceptions of 1) the proposed increase in the basic facilities charge which is denied, 2) the Basic Facilities charge for the new (MGS) will be set at $9.10, the same as that for (SGS), 3) the minimum billing provision of SGS-TOU shall be reduced in like proportion to the proposed increase.

Witness Edge proposed the availability of three new rate schedules in place of the existing Small General Service (SGS) schedule: a new SGS schedule applicable to customers with electrical requirements less than 30 kW, a Medium General Service (MGS) rate schedule applicable to customers with electrical requirements from 30 kW to less than 1,000 kW, and a Seasonal or Intermittent Service rate schedule (SI) which replaces the

previous Seasonal or Intermittent Service Rider No. 5 for loads of 30 kW or more. Witness Edge testified that the Company is proposing this change to simplify administration of the rate schedules, to enhance customer understanding of available schedules, and to minimize the costs of metering.

Commission Staff witness Watts testified that the redesign is acceptable and appropriate but that the Company's proposed rates will impose too drastic a change on some low load factor, low-use customers. The Staff recommendations would include a redesign of the MGS schedule which would produce the approved revenue while reducing the Basic Facility Charge and the Demand Charges for the first 30 kW to lessen the impact on low-load factor, low-use customers.

South Carolina Energy Users Committee witness Phillips testified that customers presently on SGS with electrical requirements of 30 kW or more should not be required to take service under the MGS schedule but should be allowed to remain on a frozen version of the present-type SGS schedule.

Witness Edge testified under cross-examination that it is not appropriate to allow customers in the load range from 30 kW to 1,000 kW to remain on the SGS schedule when MGS is the appropriate rate schedule. To do so would result in revenue erosion not provided for in this case, as it allows existing customers to choose the most advantageous rate, and would also create another frozen rate schedule to be phased out in the

future. The Commission agrees with the Company and denies the request of the SCEUC. Witness Edge strongly urged that the proposed restructuring of these rates should be implemented for all eligible customers; but if the restructuring as proposed by the Company is not adopted by the Commission, then the presently effective SGS rate design adjusted for the approved revenue increase should remain in effect.

The Commission has reviewed the testimony involving the rate designs of the new SGS/MGS/SI rate schedules and approves this restructuring as proposed by the Company with Staff's proposed recommendations in the belief that it will enhance customer understanding of available schedules and result in a significant reduction in future metering costs by greatly reducing the need for demand meters for customers with usage below 30 kW.

LGS Block Demand Charge and Transformation Discount

Witness Edge proposed continuation of the three-block demand charges for Large General Service (LGS) customers as approved in the last general rate case. The Company's proposal in this proceeding included three demand billing blocks: first 5,000 kW, next 5,000 kW, and over 10,000 kW. The Company's proposal also includes an additional $.50 and $1.00 differential in the second and third billing blocks, respectively, compared to the previously approved block demand charges in order to more fully reflect the differences in the costs to serve different load levels.

Witness Edge also proposed the continuation of the service voltage discount as it was approved in the last general rate case, with a title change to "Transformation Discount," and language changes to clarify the description covering the discount when the customer owns transformation that the Company would normally own. The Company proposed increasing the Transmission Service Transformation Discounts from $0.49/kW to $0.55/kW and $0.0004/kWh to $0.0005/kWh. The Company also proposed increasing the Distribution Service Transformation Discount from $0.60/kW to $0.75/kW, but maintaining the kWh discount at $0.0001/kWh. The pricing of both the demand block charges and the transformation discounts were supported by the Company's cost-of-service study.

Nucor witness Goins testified that the Company's declining block demand charge and transformation discounts, when combined, understated the net service voltage credit for transmission and small primary distribution customers and overstated the net service voltage credit for large primary distribution customers. He also testified that the energy charge voltage discount for transmission and distribution customers was understated and that it should not be linked to ownership of transformation facilities.

Dr. Goins stated that the credit the customer receives diverges from CP&L's cost because of CP&L's use of declining block demand charges instead of separately stated demand charge voltage service credits. He also disagreed with CP&L's

calculation of its energy charge voltage discounts and with CP&L's failure to reflect the total cost savings in the discount. Dr. Goins also testified that the energy charge voltage discount should not be dependent on ownership of transformation facilities.

Dr. Goins recommended that (1) the implicit credit in CP&L's declining block demand charges be retained; (2) the transformation discount for transmission customers be increased to $0.75 per kW; (3) the transformation discount for primary distribution customers remain at $0.75 per kW; and (4) the energy charge discount be increased to $0.0009 per kWh for transmission customers and $0.0007 per kWh for primary distribution customers.

CP&L witness Edge testified on cross-examination that (TR. Vol. 5 at 38-39, 57; Vol. 6 at 63-64) CP&L had increased the discounts in the LGS rate since the last rate case. He stated that the increases were based on the cost of service. He testified that he thought the increase was sufficient at this point and that the discount was being phased in over a number of rate cases. He stated that the additional discounts given to some customers had to be made up for by other customers and therefore he did not think it would be appropriate to shift more cost at this time.

Having considered the evidence on this issue, the Commission concludes that it is reasonable to gradually implement voltage level discounts to avoid severe impacts on specific customers.

The Commission believes that such discounts are cost-based and that the changes in them proposed by the Company are appropriate. The Commission therefore approves the Company's proposed declining demand blocks and transformation ownership discounts incorporated in the LGS schedule.

The Commission has reviewed the evidence and concludes that the three-block demand structure and transformation discounts proposed by the Company for the LGS schedules are appropriate and are therefore approved. However, no increase in the Basic Facilities Charge is approved.

Lighting Class

The Company proposed five active schedules for its Lighting class of customers with an overall increase of 1.6 percent because of the higher-than-average rate of return calculated for this class under both the present and proposed rates. The only proposed increase in the Area Lighting Service (ALS), Street Lighting Service (SLS), and Street Lighting Service Residential Subdivisions (SLR) schedules is an increase in the prices for retrofit sodium-vapor fixtures, which the Commission approves as filed at the level commensurate with the approved revenue increase. The Commission also approves the discontinuation of the 2,500 lumen incandescent fixtures in the SLS Schedule. In addition, the Commission approves the Company's proposals to increase the Traffic Signal Service Schedule proportionally to the approved revenue increase as well as, the minimum charge in

the Traffic Signal Service Schedule and the connect/disconnect charge in the Sports Field Lighting Schedule.

Service Riders, Plans, and Service Regulations

The Company proposed to restrict the availability of Seasonal or Intermittent Service Rider No. 5 to existing Rider No. 5 customers with electrical requirements of less than 30 kW until the next occurrence of their first facilities charge month at which time they will be automatically transferred to the SGS schedule. Existing customers with electrical requirements of 30 kW and above would be transferred automatically to the SI schedule upon approval of the SI schedule. The Company proposed an increase in the charges and credits in Rider No. 5 to reflect the Company's cost of providing service under this Rider. The Commission hereby approves the Company's proposed changes for Rider No. 5.

The Company proposed to restructure Highly Fluctuating and Intermittent Load Rider No. 9 to base the charge for serving such loads on the kVa capacity which must be installed to maintain proper voltage and to remove its availability for breaker or fault-testing laboratories. The Company also proposed to withdraw Standby and Supplementary Service Time-Of-Use Rider No. 61, under which no customers are presently receiving service, and supersede it with a new Back-Up and Supplementary Service Rider No. 66. Concurrently the Company proposed to restrict the availability of Standby and Supplementary Service Rider No. 7 to

exclude new applications received on and after the date of the Company's filing in this docket and increase the charges in Rider No. 7 to better reflect the Company's cost incurred in providing standby service. There being no opposition to these proposals, the Commission adopts the Company's recommendations but times the exclusion of new applications to the effective date of this Order.

The Company proposed modifications to Cotton Ginning Rider No. 42, whereby it would be used in conjunction with the new Seasonal or Intermittent Service Schedule (SI). Rider No. 42 would be available for cotton ginning customers agreeing to curtail operation of their equipment upon a 30 minute notice from the Company. The monthly bill would be computed in accordance with the new SI schedule, except that the seasonal facilities charges would be waived to compensate the customer for curtailing the customer's energy use at the Company's request.

The Company proposed continuation of Curtailable Load Rider No. 58. This Rider provides for a credit to participating General Service customers who agree to curtail their electrical load to a specified "firm demand" level. The credit is paid to the customer based on the difference between their billing demand for the month and the contracted firm demand level. Provisions in the Rider allow the customer to choose between 4-hour or 8-hour curtailable periods with 200-hour or 400-hour cumulative 12-month maximums, respectively. Curtailments may be based on

capacity or economy (energy cost) conditions. CP&L's proposed curtailable credits ($3.50 per kW for 8-hours and $2.50 per kW for 4-hours) as stated by witness Edge (TR. Vol. 5 at 130) were originally calculated in 1982 based on embedded combustion turbine capacity. Mr. Edge further testified that based on calculations using the incremental cost of a new combustion turbine with a 5-year levelized carrying charge, which includes the effects of inflation for 5 years, the resulting 8-hour discount is $3.10. CP&L, however, chose to leave the discount at the $3.50 level, rather than lower it, to provide stability and a consistent price signal to those customers currently receiving service under Rider No. 58.

Nucor witness Goins stated in prefiled testimony that the credits proposed by CP&L were too low. He further presented exhibits and testimony which proposed credits of $7.00 and $5.00 for the 8-hour and 4-hour curtailments, respectively. Dr. Goins disagreed with CP&L's use of a 68 percent coincidence factor and stated that the correct value to use should be 100 percent. Dr. Goins also disagreed with CP&L's calculation of the fuel credit for the 8-hour curtailment credit stating that it should be calculated based upon the difference between combustion turbine fuel cost and average fuel cost. Dr. Goins also disagreed with CP&L's use of real rather than nominal carrying charges as utilized in his exhibits. In addition, Nucor proposed a penalty structure for failure of the customer to comply with a capacity

curtailment request. Additionally, Nucor proposed the elimination of the Economy Curtailment provision in Rider No. 58.

Commission Staff witness Watts presented a curtailable load credit of $3.70 (8-hour) based on using an 85 percent coincidence factor and a new combustion turbine. Mr. Watts further recommended the elimination of the 4-hour curtailable credit because the 8-hour period provides more value to the system and should therefore be standardized.

The Commisssion, after considering all the evidence presented on this issue, concludes that Nucor's proposal to eliminate the Economy Curtailment portion of Rider No. 58 is denied. In addition, the proposal by Nucor to adopt the penalty structure as proposed by witness Goins is denied and the language currently in Rider No. 58 will remain in effect. The Commission further adopts Staff witness Watts proposal to eliminate the 4-hour curtailable period from Rider No. 58. The Commission has reviewed the Company's proposal to maintain the Curtailable Credit of $3.50, Staff's proposal of $3.70 and Nucor's proposal of $7.00. In order to encourage the use of the Curtailable Load Rider and to obtain the objectives of such Rider, the Commission believes that the credit should be raised to a level somewhat higher than that proposed by the Company and Staff. On the other hand, the Commission is also aware that if the credit is set at too high a level, an adverse impact on the Company and its other ratepayers will result. Therefore, in an effort to encourage the

use of the Rider and also in an effort to ensure that an adverse impact will not result, the Commission will set the Curtailable Credit at $5.00. This level is subject to re-examination in future cases to ensure the appropriateness thereof.

The Company proposed to modify its Service Regulations to incorporate load build-up and suspension of service provisions previously addressed in Rider No. 5, increase the Service Charge to $13.00, and increase the Reconnect Charge to $15.00 during business hours and $30.00 during other than normal business hours. These changes were proposed to more nearly recover the costs of providing such service. Other proposals by the Company included revisions to the charges and credits specified in Plan E and removal of the Revenue Credit allowance for temporary service customers under Plan E. All changes in charges and provisions included in the Company's proposed service riders, plans, and Service Regulations and Plan E are approved as filed, except for the proposed increases to the service charge, and reconnect charges, which are denied.

Based on its review of the Company's rate design, the Commission concludes that the rate design, rate schedules, and terms and conditions for service proposed by the Company should be approved as modified herein. All other charges and options in tariffs, service regulations, and riders proposed by the Company not addressed elsewhere and not opposed by any other party are approved.

Sales and Franchise Tax or Payment in Lieu Thereof

In accordance with the Commission's order in the last general rate case, witness Edge proposed tariffs which incorporate the change to collect sales and franchise taxes or fees directly from customers within the jurisdiction of the local or state body assessing such charges. Upon approval, the Company will separately state these charges on the affected customers' monthly bills.

Commission Staff witness Watts proposed somewhat different language to be included on the Company's tariffs to more clearly explain this charge.

The Commission approves the inclusion of this provision in the Company's tariffs with the language as proposed by witness Watts to read as follows:

> "SALES AND FRANCHISE TAX OR PAYMENT IN LIEU THEREOF:
> To the above charges will be added any applicable South Carolina Sales Tax, and for those customers within any municipal or other local governmental jurisdiction, an appropriate amount to reflect any franchise fee, business license tax, or similar percentage fee or tax, or charge in lieu thereof imposed by such entity."

The Commission also directs the Company to itemize any said tax or fee as a separate line item on the customer's monthly bill.

Uncontested Rate Design Proposals

Witness Edge proposed numerous changes to the Company's tariffs that were uncontested by the parties in this proceeding. These changes, as summarized below, are approved.

Payment Provisions

The Company revised its residential schedules to indicate that all bills are payable within 25 days from the date of the bill in lieu of the 15-day period currently stated in the residential schedules. The payment period applicable to general service schedules was proposed to remain at 15 days. The Company further proposed a change in the Payment Provision of all schedules to permit a charge of 1 percent for bills not paid on or before the expiration of 25 days from the date of the bill, effective on and after January 1, 1989. The late payment charge for residential customers would not be applicable when the customer (1) has no previous arrears during the past 12 months, and (2) has been a customer at this location for a continuous 12-month period. The Commission is of the opinion that those customers who pay after 25 days from the date of the bill should be responsible for the carrying cost instead of the Company's other customers. The Commission concludes that the late payment charge of 1 percent is within the limits as stated in

R.103-339(3) of the Commission's Rules and Regulations. The South Carolina Energy Users Committee's request for a waiver of the late payment charge for Industrial customers is denied.

Other

The filing by the Company with the Commission, of quarterly reports for its retail electric and total jurisdictional operations, including rate of return on approved rate base; return on common equity (allocated to retail electric operations); earnings per share of common stock; and debt coverage ratio of earnings to fixed charges, enables the Commission to maintain supervision of the Company's financial conditions during periods other than a general rate case proceeding. The Commission therefore finds that the Company should continue filing such reports and that such reports should be filed within forty-five (45) days of the end of the calendar quarter which is the subject of such reports.

The Commission finds that the Company should maintain its books and records for its South Carolina Retail Electric Operations utilizing FERC Uniform System of Accounts.

The Commission further finds that the fuel factor to be included in the approved rates is the current fuel factor of 1.425 cents per kWh.

The Consumer Advocate made a recommendation that the Company abandon its New Customer Deposit policy and require all new residential customers to make a security deposit. The Commission

finds that this recommendation should be denied because the Company is now handling customer deposits properly pursuant to our regulations and in the best interest of their customers. The Consumer Advocate also made a recommendation that the Company be required to perform a class cost of service study by March 1989, based on year-end 1987 data. The Commission also denies this recommendation at this time but will consider it when CP&L files for further rate relief. The Consumer Advocate also requests that the Company develop and file within sixty (60) days written training manuals for its customer service personnel which direct these employees to discuss time-of-use rates, as well as other rates, to encourage their use and acceptance. The Commission denies this request because there is no evidence that the Company's customer service personnel are not adequately trained concerning time of use rates and pursuant to our regulations, customers are provided with information at the time of application and annually concerning these rates. The Consumer Advocate also requests that the Commission order the Company to prepare and begin filing within sixty (60) days, quarterly reports concerning the activities of CP&L's Marketing Division. The initial reports should begin with the first quarter of 1988. The Commission denies this request finding that it is not necessary at this time that the Company file such reports.

IT IS THEREFORE ORDERED:

1. That Carolina Power & Light Company shall implement the rate designs, rate schedules, and terms and conditions for service as proposed by the Company or as modified herein to be effective for service rendered on and after August 31, 1988.

2. That the Company file for approval by August 31, 1988, rate schedules in accordance with the findings contained herein.

3. That the Company file the Reports identified herein in accordance with our findings.

4. That this Order remain in full force and effect until further Order of the Commission.

BY ORDER OF THE COMMISSION:

Caroline N. Thomas
Chairman

ATTEST:

Charles W. Ballentine
Executive Director

(SEAL)

CAROLINA POWER & LIGHT COMPANY
APPROVED DEPRECIATION ACCRUAL RATES
INCLUDES NET SALVAGE

Production Plant/Unit	Approved Depreciation Accrual Rate
GROUP #1	
Asheville #1	0.03122
Asheville #2	0.02981
Roxboro #1	0.03012
Roxboro #2	0.03378
Roxboro #3	0.02827
Roxboro #4	0.02658
Mayo #1	0.02822
TOTAL GROUP #1	0.02850
GROUP #2	
Cape Fear #1	0.03831
Cape Fear #2	0.04149
Cape Fear #5	0.04012
Cape Fear #6	0.04320
Lee #3	0.03853
Robinson #1	0.03789
Weatherspoon #3	0.03990
Sutton #3	0.04382
TOTAL GROUP #2	0.04129
GROUP #3	
Lee #1	0.07256
Lee #2	0.05744
Sutton #1	0.07186
Sutton #2	0.10249
Weatherspoon #1	0.03905
Weatherspoon #2	0.07917
TOTAL GROUP #3	0.07382
TOTAL FOSSIL STEAM @ 12/31/85	0.03428

NOTE: Fossil Steam rates include 5% negative salvage for FERC Accounts 311 and 312 and 5% positive salvage for FERC Account 316.

CAROLINA POWER & LIGHT COMPANY
APPROVED DEPRECIATION ACCRUAL RATES
INCLUDES NET SALVAGE

Production Plant/Unit	Approved Depreciation Accrual Rate
NUCLEAR PLANTS	
Robinson #2	0.044842
Brunswick #1	0.029723
Brunswick #2	0.030268
Nuclear Excluding Harris @ 12/31/86	0.033759
Harris #1 @ 4/30/87	0.026211
TOTAL NUCLEAR	0.028530
HYDRO UNITS	
Blewett	0.012712
Tillery	0.013470
Walters	0.015958
Marshall	0.013392
TOTAL HYDRO @ 4/30/85	0.014140
OTHER UNITS	
Cape Fear	0.036170
Weatherspoon	0.037664
Lee	0.036694
Sutton	0.035294
Roxboro	0.034283
Robinson	0.034267
Blewett	0.038196
Morehead	0.036448
Darlington	0.039200
Wilmington	0.038781
TOTAL OTHER @ 4/30/85	0.037589

NOTE: Nuclear rates include 5% negative salvage for FERC Accounts 321 and 322 and 5% positive salvage for FERC Account 325. Hydro and Other Production rates include 0% salvage. Terminal decommissioning of the nuclear plants is not covered in this table but is addressed separately in other parts of this Order.

CAROLINA POWER & LIGHT COMPANY
APPROVED DEPRECIATION ACCRUAL RATES
INCLUDES NET SALVAGE

		APPROVED RATES		
	NON-PRODUCTION PROPERTY	AVERAGE SERVICE LIFE	NET SALVAGE	ANNUAL ACCRUAL RATE
350	Land Rights	75S1.5	0%	0.01336
352	Structures & Improvements	60R3	-30%	0.02241
353	Station Equipment	50L1	-5%	0.02008
354	Towers & Fixtures	50S2	-30%	0.02749
355	Poles & Fixtures	30L1.5	-40%	0.05181
356	Conductors & Devices	45L1.5	-25%	0.02912
359	Roads & Trails	75R4	0%	0.01643
	TOTAL TRANSMISSION @ 12/31/85			0.02699
360	Land Rights	30R3	0%	0.04622
361	Structures & Improvements	40L0.5	-15%	0.03020
362	Station Equipment	38L1	-25%	0.03391
364	Poles, Towers & Fixtures	33L0	-50%	0.04698
365	OH Conductor & Devices	35L0.5	-35%	0.04271
366	Underground Conduit	50R4	-5%	0.01877
367	Underground Conduit & Devices	35R2	0%	0.02913
368	Line Transformers	30S1	10%	0.02687
369	Services	40L0.5	-30%	0.02935
370	Meters	30S1	-35%	0.04804
371	Installation on Customer Premises	12L0.5	0%	0.07663
373	Street Lighting & Signal	24L0	0%	0.03617
	TOTAL DISTRIBUTION @ 12/31/85			0.03725
389	Land Rights	75S4	0%	0.01410
390	Structures & Improvements	40S1	25%	0.01891
391	Office Furniture & Equipment	20L0	15%	0.04453
392	Transportation Equipment	8L1.5	25%	0.06718
393	Stores Equipment	25L1.5	40%	0.01641
394	Tools, Shop and Garage	35R2	15%	0.02403
395	Laboratory Equipment	15L0	5%	0.07518
396	Power Operated Equipment	12S2	35%	0.03475
397	Communication Equipment	20L1	5%	0.04937
398	Miscellaneous Equipment	35S1	5%	0.02464
	TOTAL GENERAL @ 12/31/85			0.04951